EPRI

Hydro Life Extension Modernization Guides

Volume 2: Hydromechanical Equipment

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Hydro Life Extension Modernization Guides

Volume 2: Hydromechanical Equipment

TR-112350-V2

Final Report, August 2000

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This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Hydro Life Extension Modernization Guides: Volume 2 Hydromechanical Equipment, EPRI, Palo Alto, CA: 2000. TR-112350-V2.

REPORT SUMMARY

This guideline is the second in a series of guidelines for assessing the needs and benefits and evaluating the cost and economic justification of life extension and modernization alternatives at hydroelectric plants and for implementing the selected plan. This volume covers the hydromechanical aspects of hydroelectric plants, comprising the turbine and its associated components.

Background

Hydroelectric power generation is a proven vital source of electricity in the United States and worldwide. Many hydroelectric plants have been reliably generating electricity for more than 50 years. As these facilities continue to age, decisions must be made concerning retirement, continued maintenance and operation, or modernization and redevelopment. As experienced personnel retire and leave utility companies, the need for guidance in making these critical decisions becomes even more important. To address these needs, EPRI has concluded that there is a crucial need for guidance in helping utility managers and owners make critical decisions on the future of their plants. In 1989, EPRI issued 3 volumes of Modernization Guidelines, which have been widely used by the industry. This present series of guidelines will update the 1989 guides and expand them to cover the entire plant.

Objective

To provide technical information and data on hydromechanical components that can be used as input to the life extension and modernization of hydropower plants.

Approach

The project team drew on the results of an extensive literature search and review, as well as solicitation of user needs from EPRI hydro group members, to update the hydromechanical information presented in the EPRI "Hydropower Plant Modernization Guide" published in 1989.

Results

This volume of the *Hydro Life Extension Modernization Guides* provides technical information and data that can be used as input to the life extension and modernization (LEM) planning process as developed in Volume 1. It is a technical resource for engineers and planners to assist them with the development of the LEM Plan for a particular plant and the design of projects for implementation covering turbines, wicket gates, shafts and bearings, governing equipment, inlet valves, and other hydromechanical components.

The hydraulic turbine is a primary candidate for modernization to improve turbine performance and reliability and, in some cases, reduce costs. The turbine runner is usually the most significant turbine component for modernization consideration, based on both cost and upgrade potential.

Modern turbines have significant advantages over older turbines. Advances in analytical, computer, and model testing methods as well as materials have allowed improvements in all aspects of performance. Uprating the turbine affects other components of the water passages and power plant and can have implications for licensing requirements. Reshaping wicket gates, refining nozzle assembly and deflector design, converting governing equipment from mechanical to electronic components, and modernizing turbine inlet valves are other important options with a potential to improve performance and reliability and reduce maintenance costs.

EPRI Perspective

Technical aspects covering Electromechanical, Auxiliary Mechanical and Electrical, Civil and other Plant issues, along with Protection, Control and Automation will be contained in the subsequent five volumes. The overall aims of the program are:

- To compile information on available and developing technology
- To develop guidelines to assessing needs for life extension and modernization and developing a cost-effective life-cycle plan
- To provide technical data and information required for implementation
- To identify license implications of any upgrades
- To identify improvements that can decrease environmental impacts
- To produce a resource tool for experienced and novice utility engineers

Keywords

Life Extension
Modernization
Hydro power
Asset Management
Hydraulic Turbines
Hydromechanical Equipment

ABSTRACT

EPRI's 7 Volume set of Guidelines for Life Extension and Modernization of Hydro Plants deals with how to formulate an integrated plan for an entire plant from "water to wire". This second volume of the Guidelines provides technical information on the hydromechanical aspects of the plant:

- turbine runner
- wicket gates and wicket gate operating mechanism
- Pelton nozzle assemblies and deflectors
- shaft and bearings
- governing equipment
- turbine inlet valve (TIV)
- other turbine components

Volume 2 updates the hydromechanical information presented in the EPRI "Hydropower Plant Modernization Guide[1]" published in 1989.

[1] *Hydropower Plant Modernization Guide, EPRI Palo Alto, CA: 1989. GS-6419*

ACKNOWLEDGMENTS

A number of individuals provided information and contributed to the production of this report. Valuable input and comments were received from representatives of the project team including BC Hydro International Ltd. and Acres International Ltd. A review of this document was provided by EPRI Hydro Generation Target Group and EPRI staff.

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1
INTRODUCTION AND SCOPE

1.1 Volumes 1 to 7

Volume 1 of the *Hydro Life Extension Modernization Guides*[1] (referred to subsequently as 'Volume 1') dealt with how to formulate an integrated plan for an entire plant - from "water to wire". It did not cover the technical specifics for each plant area but required that more detailed technical information for each plant area be acquired.

Volumes 2 to 7 of these guidelines will provide the more detailed information required to successfully utilize the Volume 1 document. Volumes 2 to 7 consist of:

- Volume 2 - Hydromechanical Equipment
- Volume 3 - Electromechanical Equipment
- Volume 4 - Auxiliary Mechanical Systems
- Volume 5 - Auxiliary Electrical Systems
- Volume 6 - Civil and Other Plant Components
- Volume 7 - Protection, Control and Automation

1.2 Volume 2 - Hydromechanical Equipment

The hydromechanical aspects of the plant refer broadly to the turbine and its associated components. For the purpose of this volume the systems will be broken into:

- turbine runner
- wicket gates and wicket gate operating mechanism
- Pelton nozzle assemblies and deflectors
- shaft and bearings
- governing equipment
- turbine inlet valve (TIV)
- other turbine components (discharge ring, stay ring, etc.)

[1] *Hydro Life Extension Modernization Guides: Volume 1 - Overall Process*, EPRI, Palo Alto, CA: 1999. TR-112359-V1

Volume 2 updates the hydromechanical information presented in the EPRI "Hydropower Plant Modernization Guide[2]" published in 1989.

The hydraulic turbine is a primary candidate for modernization to improve turbine performance and reliability and, in some cases, reduce costs. The turbine runner is usually the most significant turbine component for modernization consideration, based on both cost and upgrade potential.

Modern turbines have significant advantages over older turbines. Advances in analytical, computer and model testing methods as well as materials have allowed improvements in all aspects of performance. Because old turbine runners deteriorate during their operating life and design techniques of the time did not have the benefits of modern techniques and computerization, the opportunity for modernization can be very cost effective.

Modernizaton of the turbine, upgrading or uprating, can result in increased flows through the unit and increased energy. Increased flows (and output) can affect licensing requirements (refer to Volume 1, Section 6). Increased output of energy can affect other components of the water passages and powerplant.

The effect of turbine modernization on the overall plant is a critical aspect of any improvement plan and will be covered in these guidelines (refer to Section 5.9).

Wicket gates regulate the flow of water to the runner for reaction turbines. Reshaping of the wicket gates, in conjunction with turbine runner modernization, can improve the hydraulic performance of the turbine. Similarly, for impulse turbines, refinement of nozzle assembly and deflector design, in conjunction with runner modernization, can improve hydraulic performance.

Governing equipment for hydraulic turbines performs the critical functions of speed regulation, load control, turbine start-up and turbine shut down. Major opportunities for life extension and modernization include rehabilitation, converting from mechanical to electronic components and complete replacement.

Turbine inlet valves (TIV) isolate the turbine from the penstock during unit shut down as well as providing emergency functions. Life extension/modernization of the TIV primarily centres on improving reliability and reducing maintenance costs and is linked to any modernization plans for the turbine.

"Other turbine components" refers to all other turbine components such as the spiral case or housing, baffle plates, stay vanes, and discharge and wear rings.

[2] *Hydropower Plant Modernization Guide, EPRI Palo Alto, CA: 1989. GS-6419*

1.3 Purpose of Volume 2

Volume 1 provides the overall process for developing a life extension and modernization plan (LEM Plan) for a plant. For most steps in the process, technical information is required so that the needs (i.e. life extension requirements) and opportunities (i.e. modernization possibilities) of the plant can be clearly defined and addressed in terms of actual activities or plant projects.

The purpose of this Volume is to provide technical information and data which can be used as input to the life extension and modernization planning process as developed through Volume 1. Volume 2 is used *after* the screening of facilities is completed and plants suitable for life extension and modernization studies are selected in Volume 1, Section 3. It is a technical resource for engineers and planners to assist them with the development of the LEM Plan for a particular plant and the design of projects for implementation.

1.4 How to Use Volume 2

Volume 2 presents a step-by-step method to assess the potential of components for life extension and/or modernization. Volume 2 comprises:

Section 1: Introduction. Explains the needs, concepts, objectives and scope of Volume 2. The user will gain an understanding of what the volume contains, whether it will be applicable to the user's needs and how to use these guidelines.

Section 2: Background to Life Extension and Modernization. Discusses a utility's approach to life extension and modernization, including the policies and principles that should be in place.

Section 3: Screening. This is the first step of the life extension and modernization process. The user obtains the necessary information about the hydromechanical aspects of the unit. In many cases this information will clearly justify proceeding directly to Section 4 and undertaking a more detailed evaluation of condition and performance. Where it is uncertain, the user is led through the necessary steps of a desktop study to screen and prioritize the hydromechanical aspects of the plant in terms of *most likely to yield benefit from life extension and modernization*

Section 4: Evaluations of Condition and Performance. Focuses the user on a more detailed assessment of the present condition and performance of the hydromechanical components of the plant. This assessment is compared to the original design parameters of the plant to determine the scope of life extension activities.

Section 5: Potential for Improvements. Covers the modernization opportunities available for hydromechanical equipment and how to assess them.

Section 6: Estimates of Costs and Benefits. Provides the user with cost estimating information for various levels of investigation. Also discusses the benefits, power and non-power, of life extension and modernization activities.

Section 7: Optimization of Alternatives (Feasibility). Covers the more detailed investigative activities available for use during the feasibility stage of the life extension and modernization process. The activities undertaken assist the user to optimize the LEM Plan to be used for the plant.

Section 8: Implementation. Focuses on those activities required to implement the selected life extension and modernization plan and the details required from the hydromechanical perspective to successfully complete the project.

Appendix A: Annotated bibliography of case histories, reports of new technologies and processes, and other published papers provide supporting information and opportunities for further reading.

Appendix B: Procurement guides for writing specifications for the purchase of new runners, model testing services and governors.

Appendix C: Outlines sources of information for contacting potential suppliers of hydromechanical components for further information.

Appendix D: US Army Corps of Engineers (USACE) "Condition Rating Procedures/Condition Indicator for Hydropower Equipment". Sections pertaining to hydromechanical equipment are reproduced. Document is part of the USACE's Repair, Evaluation, Maintenance and Rehabilitation Research Program (REMR).

Appendix E: Glossary of Terms. A compilation of the hydraulic turbine and pump turbine terminology used in this Volume.

Volume 2 is the technical resource for the hydromechanical equipment in the overall process. Figure 1-1 shows how the various sections of Volume 2 provide information to support the development of the LEM Plan. This flowchart should be referred to on an ongoing basis as the user works through the condition assessment and other technical aspects of the Volume 2 to ensure that all necessary information is fed back into the Volume 1 process. The flowchart is adapted from the flowchart in Figure 1-2 of Volume 1 of these Guidelines.

Volume 2 is designed to provide a step by step process to identify and define projects that either extend equipment service life (life extension) or upgrade (modernization) the equipment in terms of performance. The general steps are:

1. Familiarization of what life extension terms, such as rehabilitation, and modernization really mean and clarification of the objectives of hydro plant rehabilitation (Section 2).

2. Screening (Section 3).

3. Systematic evaluation of the condition and performance level of plant equipment using a defined process (Section 4)

4. Systematic evaluation the "upgradability" and modernization potential of plant equipment to improve plant performance levels and reduce resource requirements (labour, expenditures) (Section 5).

5. Estimation of the "ball park" costs and benefits of all projects identified and roughly defined in Steps 3 and 4 above for input into the LEM Plan. (Section 6)

6. Based on an iterative approach to developing the LEM Plan, some projects (particularly modernization projects) will require a detailed feasibility study to determine their technical feasibility and economic worth (Section 7). Most of the life extension projects, which only restore equipment to its original condition and level of service, will not require a detailed feasibility study. A simple evaluation of the cost of rehabilitation vs. replacement may be all that is warranted in some cases. Projects that have an impact on overall plant operation or other plant equipment will require more detailed evaluation and optimization of alternative project scenarios.

7. Project implementation. (Section 8)

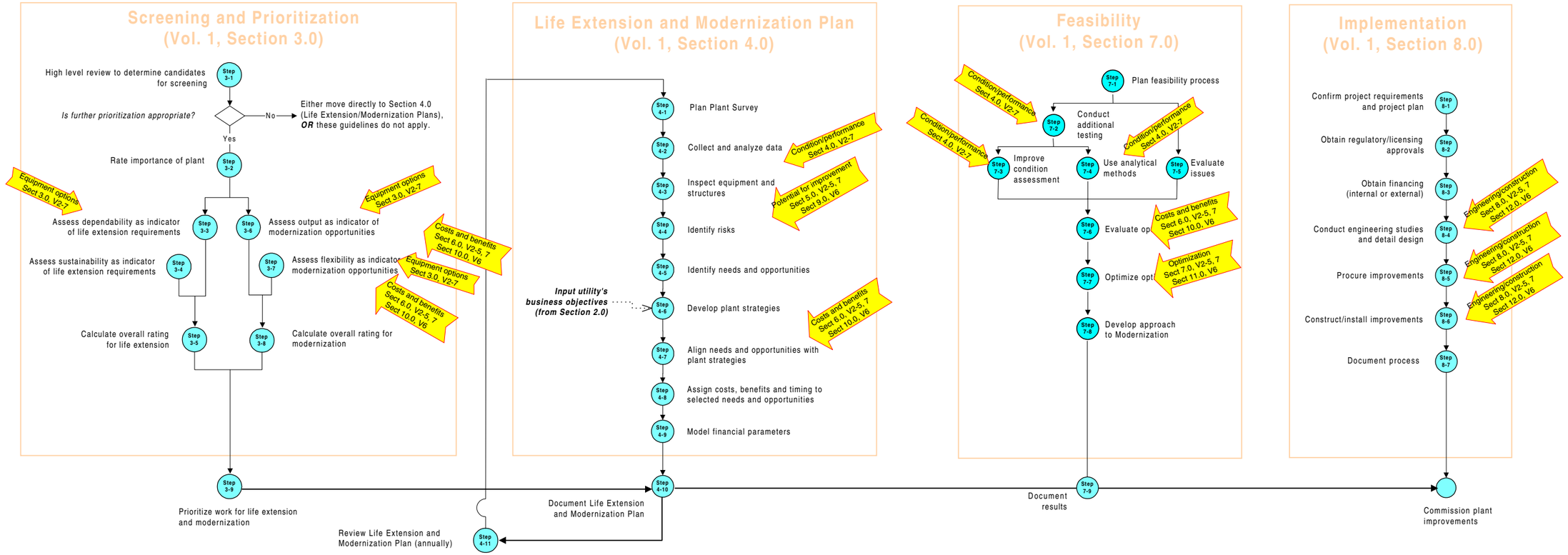
Screening and Prioritization
(Vol. 1, Section 3.0)
High level review to determine candidates for screening
Step 3-1
Is further prioritization appropriate?
No
Either move directly to Section 4.0 (Life Extension/Modernization Plans), OR these guidelines do not apply.
Yes
Rate importance of plant
Step 3-2
Equipment options Sect 3.0, V2-7
Assess dependability as indicator of life extension requirements
Step 3-3
Step 3-6
Assess output as indicator of modernization opportunities
Equipment options Sect 3.0, V2-7
Costs and benefits Sect 6.0, V2-5, 7 Sect 10.0, V6
Assess sustainability as indicator of life extension requirements
Step 3-4
Step 3-7
Assess flexibility as indicator of modernization opportunities
Equipment options Sect 3.0, V2-7
Costs and benefits Sect 6.0, V2-5, 7 Sect 10.0, V6
Calculate overall rating for life extension
Step 3-5
Step 3-8
Calculate overall rating for modernization
Step 3-9
Prioritize work for life extension and modernization
Life Extension and Modernization Plan
(Vol. 1, Section 4.0)
Step 4-1
Plan Plant Survey
Step 4-2
Collect and analyze data
Condition/performance Sect 4.0, V2-7
Step 4-3
Inspect equipment and structures
Potential for improvement Sect 5.0, V2-5, 7 Sect 9.0, V6
Step 4-4
Identify risks
Step 4-5
Identify needs and opportunities
Input utility's business objectives (from Section 2.0)
Step 4-6
Develop plant strategies
Costs and benefits Sect 6.0, V2-5, 7 Sect 10.0, V6
Step 4-7
Align needs and opportunities with plant strategies
Step 4-8
Assign costs, benefits and timing to selected needs and opportunities
Step 4-9
Model financial parameters
Step 4-10
Document Life Extension and Modernization Plan
Review Life Extension and Modernization Plan (annually)
Step 4-11
Feasibility
(Vol. 1, Section 7.0)
Step 7-1
Plan feasibility process
Condition/performance Sect 4.0, V2-7
Step 7-2
Conduct additional testing
Condition/performance Sect 4.0, V2-7
Condition/performance Sect 4.0, V2-7
Step 7-3
Improve condition assessment
Step 7-4
Use analytical methods
Step 7-5
Evaluate issues
Step 7-6
Evaluate op
Costs and benefits Sect 6.0, V2-5, 7 Sect 10.0, V6
Step 7-7
Optimize opt
Optimization Sect 7.0, V2-5, 7 Sect 11.0, V6
Step 7-8
Develop approach to Modernization
Step 7-9
Document results
Implementation
(Vol. 1, Section 8.0)
Confirm project requirements and project plan
Step 8-1
Obtain regulatory/licensing approvals
Step 8-2
Obtain financing (internal or external)
Step 8-3
Engineering/construction Sect 8.0, V2-5, 7 Sect 12.0, V6
Conduct engineering studies and detail design
Step 8-4
Engineering/construction Sect 8.0, V2-5, 7 Sect 12.0, V6
Procure improvements
Step 8-5
Engineering/construction Sect 8.0, V2-5, 7 Sect 12.0, V6
Construct/install improvements
Step 8-6
Document process
Step 8-7
Commission plant improvements

Figure 1-1
LEM Flowchart

2
BACKGROUND TO LIFE EXTENSION AND MODERNIZATION

2.1 Introduction

This Volume covers the main hydromechanical equipment in a hydro plant. Auxiliary mechanical equipment, such as bearing lubrication systems and compressed air systems, are covered in Volume 4 "Auxiliary Mechanical Systems" of these Guidelines.

This volume provides detailed technical information on the following equipment:

- Turbine runner
- Shaft and bearings
- Wicket gate and wicket gate operating mechanism
- Nozzle assemblies and deflectors
- Governing systems
- Turbine inlet valves (TIV)
- Other turbine components (discharge ring, stay ring, etc.)

The turbine types covered by these guidelines include:

1. Reaction turbine types: Francis, Kaplan, propeller and pump-turbines

2. Impulse turbine types: Pelton

Other turbine types (e.g. Deriaz, straight flow [rim generating], bulb, S-type and Turgo) have not been included in these Guidelines.

It is assumed that the user of the Guidelines has a basic understanding of the types of hydromechanical equipment in a hydroplant and therefore descriptions of the equipment are not provided. Appendix E contains diagrams and a glossary of terms for turbines for reference purposes reproduced courtesy of Voith Hydro.

A good reference source is "The Guide to Hydropower Mechanical Design"[1] prepared by the ASME Hydro Power Technical Committee.

2.2 Objectives of Hydro Life Extension and Modernization[2]

Each hydro life extension and/or modernization program or project has its own, sometimes unique, objectives. Among possible objectives are:

Plant Life Extension and Restoration of Original Performance Levels

- Extending equipment life
- Halting or decelerating deterioration
- Reducing forced outages or unscheduled down time
- Reducing operations or maintenance costs
- Reducing frequency of overhauls, scheduled downtime
- Reducing undesirable operating characteristics, such as vibration

Plant Modernization to Improve Plant Products and Economics

- Increasing generating capacity
- Improving efficiency
- Improving ability to control equipment data
  - remote control
  - automation
- Improving ability to deliver "ancillary services" such as voltage support, synchronous condensing capability, black start, etc.
- Matching unit performance characteristics to load or water availability, including removing 'bottlenecks" in cascade hydro systems
- Improving plant/personnel safety
- Avoiding obsolescence problems such as lack of manufacturer support or unavailability of replacement parts

[1] ASME Hydro Power Technical Committee, *The Guide to Hydropower Mechanical Design*, HCI Publications, 1996.

[2] EPRI, Palo Alto, CA, 1998. WO 5715-01, p 5-1, *Hydropower Technology Round-up Report; Part 2: Rehabilitating and Upgrading Hydro*

Risk Management and Environmental Compliance

- Reduce risk of catastrophic failure
- Improving ability to meet river flow or reservoir level requirements
- Reducing potential for environmental degradation
- Enhancing water quality
- Reducing fish mortality
- Meeting legal/licensing requirements

2.3 Trends in Life Extension and Modernization[3]

An industry benchmarking survey was conducted in conjunction with the HydroVision 98 conference. The survey provides a good sampling of general approaches and practices being implemented by hydro owners, primarily in North America, with regard to plant or component life extension and modernization. A total of 66 projects were reported. Relevant information about each project is provided in Table 2-1. The survey report presents statistics on the reasons for life extension and/or modernization, strategies employed, economic and prioritization criteria, contracting arrangements, and quality control and testing methods. Leading the list of project components approved for life extension and/or modernization are turbine runners and miscellaneous components, generator stator windings and miscellaneous components, excitation systems, and governors.

The survey report indicates that in nearly one-third of the projects reported, owners specified environmental superior technology for new plant equipment. Respondents also reported that 18% of the projects accomplished a reduction of environmental risk. The most commonly reported environmental practice is reducing the use of lubricants by the installation of self-lubricating or greaseless bearings and bushings, and/or the use of oil-less or low-oil governors.

[3] EPRI, Palo Alto, CA, 1998. WO 5715-01, p 5-4 to 5-6, *Hydropower Technology Round-up Report; Part 2: Rehabilitating and Upgrading Hydro*

Gains in Capacity and Efficiency

The HydroVision 98 benchmarking survey indicates significant improvements in capacities and efficiencies resulting from turbine and generator modernization, as follows:

	Percentage of Projects with Reported Increases	% Increase	% Increase
		Average	*Range*
Turbine Capacity	42	23.8	1-230
Generator Capacity	29	20.1	1-67
Turbine Efficiency	22	6.1	3-15
Generator Efficiency	3	1.5	1-2

The benchmarking survey report also presents statistics on the reasons for modernization, strategies employed, economic and prioritization criteria, contracting arrangements, and quality control and testing methods.

Table 2-2 presents the capacity and efficiency gains realized or expected as a result of the life extension and modernization programs and projects covered by the survey. For three of the projects, realized or expected annual energy gains (in lieu of efficiency gains) are known and are presented. The programs and projects for which capacity, efficiency or annual energy gains are known represent a total of more than 10,000 MW of capacity. The gains in capacity and efficiency presented on Table 2-2 are summarized as follows:

- The combined capacity gain of all projects is approximately 1400 MW, or nearly 14%
- The largest project capacity gain is 325 MW (Robert Moses Niagara)
- The largest capacity gain per unit is 33 MW (Shasta)
- The average efficiency gain weighted by capacity is 3.2%

The annual average energy gains for the three plants where this is known are 13%, 23% and 61% respectively. The 13% annual average energy gain is for a large plant (Beauharnois); the 23% and 61% gains are for small plants.

Table 2-1
Life Extension and Modernization Program and Projects
Adapted from *Hydropower Technology Round-Up Report; Part 2: Rehabilitating and Upgrading Hydro Plants*, EPRI, Palo Alto, 1998. WO5715-01, pgs 5-9 to 5-15

Program, Project, or Powerhouse (a)	State (U.S.), Province (Canada) or Country	Owner	Scope of Program or Project	No. of Units	MW (b)	Status (c)	Cost $million (d)
Hydro Modernization*	Tennessee and several adjacent states	Tennessee Valley Authority	variously: runner replacement, other turbine modification, generator rewinding, other generator modification, control upgrades	88		in prog.	
Forbestown*	California	Oroville-Wyandotte Irrigation District	runner replacement, other turbine modifications	1	36	comp. 1991	0.64
Yale*	Washington	PacificCorp	runner replacement, other turbine modifications, generator modifications, controls upgrade	2	125	comp. 1996	
Robert Moses Niagara*	New York	New York Power Authority	runner replacement, other turbine modification	13	2275	in prog. 2006	280
Bennetts Bridge*	New York	Niagara Mohawk Power Corporation	runner replacement, other turbine modification	1	7.5	comp. 1990	1.0
Great Falls*	South Carolina	Duke Power	turbine replacement, generator modification, controls upgrade	2	6	comp. 1992	
Stechovice*	Czech Republic	Czech Power Company CEZ, a.s.	pump-turbine and motor-generator replacement	2->1	42	comp. 1997	
Muddy Run*	Pennsylvania	PECO Energy	impeller-runner replacement, other pump-turbine modification, control upgrade	8	8	comp. 1998	40
Rocky Reach*	Washington	Chelan County PUD	runner replacement, other turbine modification, generator modification, controls upgrade	11	1380	in prog.	116
John Hollis Bankhead*	Alabama	Alabama Power Company	runner replacement, other turbine modifications	1	46	comp. 1998	4
Chippewa Falls*	Wisconsin	Northern States Power	runner replacement, other turbine modifications	6	21.6	comp. 1995	

Program, Project, or Powerhouse (a)	State (U.S.), Province (Canada) or Country	Owner	Scope of Program or Project	No. of Units	MW (b)	Status (c)	Cost $million (d)
Twin Branch*	Indiana	American Electric Power Corporation	turbine and generator replacement	6->8	7.3	comp. 1992±	
Berrien Springs*	Michigan	American Electric Power Corporation	turbine and generator replacement	4->12	7.2	comp. 1997±	
Wanapum*	Washington	Grant County PUD	runner replacement, other turbine modifications	10	900	in prog.	75
Big Creek 1*	California	Southern California Edison	runner replacement, other turbine modifications	2	36	comp 1993?	
Tafjord K2*	Norway	Tafjord Power Company	runner replacement, controls upgrade	2	28	comp.	3
Holm*	California	Hetch Hetchy Water and Power	runner replacement, controls upgrade	2	150	comp. 1993	14±
Kirkwood*	California	Hetch Hetchy Water and Power	runner replacement, other turbine modification	2	70	comp. 1997	24±
New Moccasin*	California	Hetch Hetchy Water and Power	runner replacement	2	90	in prog 1999	
Clam River	Wisconsin	Northwestern Wisconsin Electric Company	turbine modification in conjunction with powerhouse reconstruction	1		comp. 1995	0.3±
Fort Peck No. 1	Montana	U.S. Army Corps of Engineers	penstock replacement, flow meter installation	3	105	comp. 1992	18.5
Tuxedo*	North Carolina	Duke Power	runner replacement, penstock replacement	2	5	comp. 1991	
unnamed			generator rotor modification and repair			comp.	
Shasta*	California	U.S. Bureau of Reclamation	runner replacement, generator rewinding, other generator modification	3	328	in prog. 2002±	21
Amprior	Ontario	Ontario Hydro	generator modification for stiffness	2	70	comp. 1993	
Lookout Shoals*	North Carolina	Duke Power	replacement of turbine-driven exciter with generator	2	0	comp. 1996	
Major Rehabilitation	Many states	U.S. Army Corps. Of Engineers	comprehensive rehabilitation, economic revaluation, stator iron replacement				450±

Program, Project, or Powerhouse (a)	State (U.S.), Province (Canada) or Country	Owner	Scope of Program or Project	No. of Units	MW (b)	Status (c)	Cost $million (d)
Porjus	Sweden	Vattenfall	high-voltage generator (prototype test)	1	11±	comp. 1998	
Bradley Lake	Alaska	Alaska Industrial Development and Export Authority	governor control reprogramming	4	120	comp. 1993	
Robert S. Kerr Dam	Oklahoma	Grand River Dam Authority	controls upgrade, automation	4	114	comp. 1995	0.6
California Water Project	California	California Water Project	controls upgrade			in prog.	1.0±
Osage	Missouri	AmerenUE	controls upgrade, automation	10	212	comp. 1992	
Castaic	California	Los Angeles Dept. of Water and Power	controls upgrade	6	1440	comp. ?	0.9
Tränglslet	Sweden	Stora Power AB	new control system	3	330	comp. 1987	1.5
Säckingen	Germany	Rheinkraftwerk Säckingen AG	controls upgrade, automation	4	80	comp. 1997	17
Auxillary Equipment Replacement	Texas	Lower Colorado River Authority	replacement and modernization of various auxiliary systems	6 plants	270	in prog. 1999	
Asset Management	British Columbia	BC Hydro	preparation of asset management plans, identification of improvement opportunities, prioritization of projects		9746	ongoing	
Hydro Improvement	France	Electricité de France	economic evaluation in identifying and prioritizing rehabilitation projects		23100	ongoing	
Jupiá	Brazil	Companhia Energética de São Paulo	to be determined	14	1411	planned	
Hydroelectric Life Extension	Texas	Lower Colorado River Authority	economic evaluation of rehabilitation and upgrade projects, project planning	6 plants	270	in prog. 2005±	
Small Plant Rehabilitation	North Carolina South Carolina	Duke Power	project justification and prioritization			in prog.	

Program, Project, or Powerhouse (a)	State (U.S.), Province (Canada) or Country	Owner	Scope of Program or Project	No. of Units	MW (b)	Status (c)	Cost $million (d)
Hydro Modernization	Several states in eastern Midwest	America Electric Power Corporation	project planning and prioritization	17 plants	900±	in prog.	
Beauharnois*	Quebec	Hydro-Québec	variously: runner replacement, generator rewinding, controls upgrade	38	1666	in prog. 2002±	C1500
Nine Mile*	Washington	Washington Water Power	turbine and generator replacement, controls upgrade	2	6.8	comp. 1995?	
Boundary	Washington	Seattle City Light	comprehensive rehabilitation of entire plant	6	1051	in prog. 2008	88
Inks*	Texas	Lower Colorado River Authority	runner replacement, generator rewinding, controls upgrade	1	11.4	comp. 1997	6.4
Buchanan*	Texas	Lower Colorado River Authority	runner replacement, generator rewinding, controls upgrade	2	25	in prog. 19999	11.5
Austin*	Texas	Lower Colorado River Authority	runner replacement, generator rewinding, controls upgrade	2	15.0	comp. 1994	10.4
Búrfell*	Iceland	Landsvirkjun	partnering, runner replacement, generator modification, controls upgrade	6	210	in prog.	

Footnotes:

(a) Asterisk (*) indicates programs or project is listed in Table 2-2 Capacity and Efficiency Improvements.

(b) Capacity of units rehabilitated or upgraded (or planned to be rehabilitated or upgraded) prior to work; capacities are presented for comparison and may be nominal values.

(c) Status noted as follows: planned - planned or scheduled
ongoing - continuing
in. Prog. - in progress, year indicates expected completion date, where known
comp. - completed; year indicates completion date, where known

(d) Cost of program or project in US$ unless otherwise noted.

Table 2-2
Capacity and Efficiency Improvements
(In order of decreasing MW capacity prior to upgrade)
Adapted from *Hydropower Technology Round-Up Report; Part 2: Rehabilitating and Upgrading Hydro Plants*. EPRI, Palo Alto, 1998. WO5715-01, pgs. 5-16 to 5-18.

Program or Project	Owner	No. of Units	Type of Units	Capacity Prior (MW) (a)	Capacity After (MW) (a)	Capacity Gain (MW)	Efficiency Gain (b)	Cost $million (c)
Robert Moses Niagara	New York Power Authority	13	Francis	2275	2600	325	1-2%	280
Beauharnois	Hydro Québec	27 11	Francis propeller	1666			13%(d)	C1500
Jupia	Companhia Energética de Säo Paula	14	Kaplan	1411		308 (22/unit)		
Rocky Reach	Public Utility District No. 1 of Chelan County	7 4	Kaplan propeller -> Kaplan	1280	1316	36		116
Wanapum	Public Utility District No. 2 of Grant County	10	Kaplan	900	1125	225		75
Muddy Run	PECO Energy	8	pump-turbine	800*	864*	64*	4% pump 4% gen	40
Hydro Modernization Completed to date: Total program:	Tennessee Valley Authority	 23 77	varies	700±	850±	152	5.7%	
Shasta	U.S. Bureau of Reclamation	3	Francis	328	426	98		21
Burfell	Landsvirkjun	6	Francis	230	300	70	4%	
Holm	Hetch Hetchy Water and Power	2	Pelton	150	175	25		14±
Yale	PacifiCorp	2	Francis	100*	140*	9%		
New Moccasin	Hetch Hetchy Water and Power	2	Pelton	90*	76*	(14)*	1.2% expected	
Kirkwood	Hetch Hetchy Water and Power	2	Pelton	70*	80*	10%	2.5% expected	24±
John Hollis Bankhead	Alabama Power Company	1	propeller	46*	52*	6*		4
Stechovice	Czech Power Company CEZ, a.s.	2->1	pump-turbine	42	53/50 (e)	8		
Forbestown	Oroville-Wyandotte Irrigation District	1	Francis	36.3	40.7	4.4	71.%	0.64

Program or Project	Owner	No. of Units	Type of Units	Capacity Prior (MW) (a)	Capacity After (MW) (a)	Capacity Gain (MW)	Efficiency Gain (b)	Cost $million (c)
Big Creek 1	Southern California Edison Company	2	Pelton double runner	36	unknown	unknown	14%	
Tafjord K2	Tafjord Power Company	2	Pelton	28	34	6	6%	3
Buchanan	Lower Colorado River Authority	2	Kaplan	25	34	9		11.5
Chippewa Falls	Northern States Power Company	2 4	Kaplan Kaplan ->propeller	21.6	24±	2±	10%	
Austin	Lower Colorado River Authority	2	Kaplan	15.0	17.3	2.3		10.4
Inks	Lower Colorado River Authority	1	Francis	11.5	14.9	3.4		6.4
Bennetts Bridge	Niagara Mohawk Power Corporation	1	Francis double discharge	7.5	9.9	2.4	10.5%	1.0
Berrien Springs	American Electric Power Corporation	4->12	Francis to semi-Kaplans	7.2	7.2	0		
Nine Mile	Washington Water Power	2	Francis quad-runner dbl. Draft	6.8	20	13.2	23%(d)	
Great Falls	Duke Power Company	2	Francis	6	8	2		
Tuxedo	Duke Power Company	2	Francis	5	8	3		
Lookout Shoals	Duke Power Company	2	Francis	0	0.8	0.8		
Totals (approximate)		**175**		**10,300**		**1400**		

Footnotes:

(a) Capacity (MW) values do not necessarily represent official plant or unit ratings and should be considered "nominal", capacity (MW) values given are known or understood to represent maximum output, except that values noted with an asterisk (*) are known to represent best efficiency output.

(b) Nominal improvement in maximum (best gate) efficiency except as noted; see (d)

(c) Cost of program or project in US$ unless otherwise noted.

(d) Improvement in annual generation.

(e) Pump input/turbine output.

2.4 Definitions[4]

Within the hydropower industry, the terms "life extension", "rehabilitation", "modernization", "upgrade", "upgrading" or "uprating", among others, are employed to indicate the nature, extent, or result of an improvement to a hydro plant or component. These terms often appear to be used interchangeably.

For these Guidelines, the following are the "improvement" terms which are used:

> Life Extension - the replacement or improvement of components which have been the cause of higher maintenance repair, or for which failure, due to age, is expected in the forseeable future. Other terms that are close in meaning and often need interchangeably with "life extension" include: rehabilitation, retrofit, replacement and refurbishment. The term "overhaul" has a slightly different meaning and usually refers to the planned disassembly, cleaning, repair, lubrication and re-assembly of a unit or component.
>
> Modernization - the improvement of level of service and cost of service (refer to Volume 1, Section 2.3.1) measured by plant output and/or flexibility. Other terms that are close in meaning and often used interchangeably with "modernization" include upgrade, upgrading and uprating.
>
> Redevelopment - new construction of an existing plant, including replacement or substantial modification of civil, mechanical, and electrical components [definition from *Hydro Rehabilitation Practices: What's Working in Rehabilitation*].[5] This area is not covered by these Guidelines.

[4] EPRI, Palo Alto, CA, 1998, pgs. 5-6 to 5-7, *Hydropower Technology Round-up Report; Part 2: Rehabilitating and Upgrading Hydro Plants*

[5] *Hydro Rehabilitation Practices: What's Working in Rehabilitation.* HCI Publications, Kansas City, MO 1998

3
SCREENING

3.1 Screening Process in 1989 Guidelines

The turbine screening procedure developed in the 1989 Hydropower Plant Modernization Guidelines is a quick and easy process to evaluate whether the feasibility of upgrading the turbine capacity by replacing the runner should be pursued. Through this process, the user can assess the potential for turbine upgrading to avoid performing detailed, costly studies of uneconomic alternatives. A survey and point rating system is used and special measurements or tests are not required.

The screening process for runner replacement uses the following "indicators" to assess whether runner replacement should be considered:

- Runner age
- Runner condition
- Performance
- Changed operating condition
- Generator rewind need

The screening process contained in the 1989 Guidelines is a valid high level approach specifically targeted at evaluation of turbine runner replacement.

3.2 Updated Screening Process

The screening process in the remainder of this section uses the above concepts, and others, to assess life extension needs and modernization opportunities in an asset management context. A more detailed description of the screening process used in this document is set out in Volume 1, Section 3 of these Guidelines.

The screening in Volume 2 is complementary, but at a greater level of detail, to that contained in Volume 1, in that it considers each piece of equipment or component, as appropriate.

Hydromechanical equipment covers:

- turbines (different types), including pump turbines
- governing equipment

- flow control systems
- turbine hydraulic components

Using this approach for each type of equipment, a determination can be made of what are the needs and opportunities for a particular unit/plant. Screening factors relating to needs could result in life extension activity. Screening factors relating to opportunities could result in modernization activities. Needs are measured by Indicators of Dependability and Sustainability. Opportunities are measured by Indicators of Output and Flexibility.

3.3 Screening for Life Extension

The screening for life extension of hydromechanical equipment is primarily related to a high level of assessment of the Indicators of Dependability and Sustainability. These are described below.

Following this section is an annex (Section 3.4) that is common to all equipment and is contained in each technical volume of these Guidelines. This annex considers the proportional allocation of funds across each powerplant to determine if any significant anomalies are apparent. If so, they are also considered a Life Extension Indicator.

A1 Indicators of Dependability

A1.1	Condition	Knowledge of the condition of a piece of equipment
A1.2	Performance	Level of service measured by commercial availability
A1.3	Operational Risk (Safety)	Outstanding, identified or perceived risks to equipment or works.
A1.4	Costs	Assessment of maintenance costs and comparison with other plants and industry averages.

A2 Indicators of Sustainability

A2.1	Environmental Issues	Possibility or likelihood that equipment could cause an environmental impact i.e. oil leakage, atmospheric pollutants.
A2.2	Catastrophic Risk	Assessment of outstanding, identified or perceived risks that could pose a significant risk to the unit.

The intent of the needs assessment for specific equipment is to provide:

1. specific requirements for a piece of equipment

2. input to overall plant ratings and prioritization (Volume 1, Section 3).

A1.1 Condition

Indicators of condition for hydro mechanical equipment at the screening level can be obtained from a variety of sources including:

- interviews with hydro plant maintenance staff as well as technical specialists
- review of data bases including computerized maintenance management system
- previous studies on condition assessment, including test results
- review of any recent change in operation of the equipment that would result in increased wear and tear.

Condition Indicators are based on questioning:

- Does the condition of this piece of equipment significantly affect its performance?
- Is the expected remaining life of the equipment less than five years?
- Are there existing or expected changes in the use of this equipment that will result in increased degradation to its condition?
- Are there any test results that indicate poor, or worse, condition?

If the answers to one or more of the above question is YES, it identifies that the condition of a piece of equipment is a driver for life extension. It is important to note that Indicators are a qualitative assessment of the existing condition of equipment based on a review of existing and easily obtainable information. The information for the specific equipment is summarized in Table 3-1 and then used in Step 3.3 of the screening process in Volume 1.

A1.2 Performance

Indicators of Performance for hydromechanical equipment at the screening level can be obtained from a number of sources including:

- operations records of outages for each unit and each component (i.e. how many outages/year due to hydromechanical equipment on each unit).
- seriousness of outages/cost of outage in terms of lost energy and ancillary services (i.e. was there a lost opportunity cost due to the outage?).
- number of forced or unplanned outages compared to planned outages for each piece of equipment.

Performance Indicators are based on questioning:

- Is the performance now significantly decreased compared to the equipment's original performance?
- Is the performance now significantly lower than the expected performance?
- Are changes in performance expected and can they be reliably accommodated?

If the answers to one or more of the above questions is YES, it identifies that performance is a driver for life extension needs. It is important to note that Indicators are an assessment of performance, generally qualitative or approximate if quantitative, unless accurate records are readily available. The information for the specific equipment is summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

A1.3 Operational Risk

Indicators of operational risk for hydromechanical equipment at the screening level can be obtained from:

- interview with plant operations/maintenance staff on their understanding of the risks to the equipment in terms of failure or damage and the risks to worker safety.
- existing studies such as Failure Modes and Effects Analysis (FMEA) or Reliability Centered Maintenance (RCM).
- assessment by an experienced engineer familiar with the possible risks that can threaten continued equipment operation and hydro plant staff.

Operational Risk Indicators are based on questioning:

- Could something happen to a piece of equipment that would result in its failure or significant degradation in performance?
- Is it likely?
- Could something happen to a piece of equipment that could result in a life safety consideration?
- Could activities to the equipment, i.e., refurbishment, replacement, renewal mitigation those risks/hazards?

If the answers to one or more of these questions is YES, this information on operational risk identifies that the perceived operational risks warrant further study to determine life extension needs. It is important to note that Indicators of operational risk will be qualitative only. Information will be collected, collated for all equipment, summarized in Table 3-1 and incorporated in Step 3.3 of Volume 1.

A1.4 Cost

Indicators of cost for hydromechanical equipment at the screening level can be obtained from:

- computerized maintenance management systems
- financial data bases
- previous studies on cost allocation between plants, units and component equipment.

This may need to be levelized over a period of 5 years , for example, to account for any extraordinary activities. High non-equipment costs that must be allocated should also be covered, such as extensive mobilization cost (remote access).

Cost indicators are based on questioning:

- Does the cost for maintenance of a piece of equipment fall in line with costs at other plants as well as industry data bases and standards?
- Are the significant changes (increases) in the cost of maintenance from year to year?

If the answers to either of these questions is YES, it identifies whether the costs for a specific piece of equipment warrant further study to determine life extension needs. The Indicator of the assessment of costs to be summarized in Table 3-1 are at a high level. This assessment can also be used in conjunction with the Annex on cost allocations (Section 3.4).

A2.1 Environmental Issues

Indicators of environmental issues from hydromechanical equipment are primarily related to activities or events that could jeopardize the continued operation of the plant.

Most utilities have assessed the risks to their plants from various events, such as those related to spills of any hazardous substances, particularly to the water course.

Environmental Issues Indicators are based on questioning:

- Has a direct assessment on environmental issues been undertaken for the equipment, is it complete, and is it available?
- Has an assessment of the risks of spills of hazardous substances been undertaken for the equipment?

If the answer to either of these questions is YES, it will indicate that further study may be warranted to identify any life extension needs. These are summarized in Table 3-1, then used as input to Section 3 of Volume 1.

A2.2 Catastrophic Risk

Indicators of catastrophic risk from hydromechanical equipment are those related to activities or events that could pose a significant risk to the unit. While complete breakdown of the hydromechanical equipment, leading to the non-operation of the unit is a possibility, it would rarely occur without adequate warning, unless caused by an external event.

Therefore no Indicators have been included for this category for this equipment.

3.4 Annex to "Screening for Life Extension" for all Technical Volumes

Generalized Cost Allocation Screening Criteria

This annex can be used to enhance some of the qualitative screening criteria for specific pieces of equipment found in Volumes 2 through 7. It is particularly relevant for the Indicators of Dependability as used in the assessment of life extension needs. The first step will be to consider the overall cost allocation (total maintenance, excluding capital) between Powerhouse, Dam and Generating Units.[1]

Industry averages for each range between the following allocations:

Powerhouse	40 - 50%
Dam	20 - 30%
Units	30 - 40%

Where the total maintenance costs for each subcomponent exceed these industry average allocations, this may be an indicator of life extension.

For example: If the allocation of costs for units exceed 40% (subject to certain site specific conditions like the absence of a significant dam) then the unit itself can be broken down to equipment categories with an industry average cost allocation:

Generator and Turbine	70%
Exciter	15%
Governor	10%
Bearings	5%

[1] Information collected by BC Hydro for the purposes of cost allocation. The following is included under each category:
1. Powerhouse: structural, management and administration;
2. Dam: dam safety, dam maintenance;
3. Generating Units: equipment maintenance

Where maintenance cost allocations significantly exceed these proportions then this can, at a screening level, be regarded as a potential reason to consider life extension.

While this method only considers proportional allocations, a more specific assessment of maintenance cost assessment at the screening level has been included for the entire plant in Step 3.3 of the Volume 1.

3.5 Screening for Improvement Potential (Modernization)

The screening for modernization of hydromechanical equipment is primarily related to turbine upgrades and is assessed through Indicators of Output and Flexibility. Any input from this section can be then added to the more generalized assessment in Step 3.6 of Section 3 in Volume 1, to assist in improving the confidence of the overall screening process.

It is strongly suggested that screening for turbine runner replacement not be undertaken in isolation from considerations of the entire powerplant and infrastructure needs and opportunities.

The screening indicators for turbine upgrade are:

B1	Indicators of Output		
	B1.1	Capacity	Limitation of equipment to meet capability increases
	B1.2	Efficiency	Assessment of the use of the water resource
	B1.3	Equipment	Comparison with modern technologies
B2	Indicators of Flexibility		
	B2.1	Range of Products	Capability of equipment to adapt to required range of products

The screening process described in this section is intentionally broad. However, it also acknowledges that decisions on turbine upgrade potential are often complex with many interrelated factors involved. Below are a few considerations to bear in mind before proceeding with the screening process.

Francis Turbine

Francis turbines were invented in the early 1800's and at the turn of the century, the peak efficiency of the Francis turbine was approximately 82%. Through advancement in design, the efficiency of Francis turbines has increased dramatically over the years, and for certain designs, now exceeds 95%.

The historical increase in efficiency of Francis turbines is shown in Figure 3-1. As can be seen, a modern turbine will have an efficiency increase of about 5% over a 1930 design. However, this does not mean that a 5% increase in turbine efficiency will occur when a new runner of modern design is installed in a 1930 vintage turbine. Hydraulic losses in the runner represents about 30% of the total losses. Other areas for losses include runner disc friction, seal leakage, the spiral case, the distributor, and the draft tube. For medium and high head designs, the stay ring can have a significant influence on efficiency. For lower head designs, energy recovery in the draft tube becomes increasingly important.

Generalizing somewhat, it is reasonable to expect that by installing a new runner in an older turbine, an efficiency gain of roughly 40% of that indicated in Figure 3-1 may be possible. This assumption can, in fact, be conservative as it assumes that the runner for the old turbine is in reasonably good condition. The efficiency of the existing turbine may have deteriorated over the years because of blade distortion due to frequent cavitation repairs, increased roughness due to cavitation damage, runner blade damage from debris, or increased runner seal clearance.

Propeller and Kaplan Turbines

Propeller and Kaplan turbines, while having a shorter history than Francis turbines, have also shown efficiency improvements over the years, as illustrated in Figure 3-2. A modern Kaplan turbine will have a peak efficiency approximately 4% higher than a 1930 design. As discussed for the Francis turbines, this efficiency improvement cannot be achieved by replacing the runner only. A predominant loss, particularly when operating at high load, is in the draft tube.

Generalizing again, it is estimated that with a new runner, an efficiency improvement roughly 40% of that shown in Figure 3-2 can be expected.

Other Considerations in Uprating Turbines

When uprating a turbine with a new runner, the effect on other equipment or other equipment components must be considered. This includes:

- Turbine runaway speed: If the new runner has a higher runaway speed, the stress levels in the generator may be excessive on overspeed.
- Turbine hydraulic thrust: An increase in hydraulic thrust can overload the thrust bearing as well as the supporting members. Generally, this has not been a problem with turbine uprating.
- Turbine and generator shaft: A significant increase in turbine output can result in higher than normal stress levels in the turbine or generator shaft.
- The influence of the new runner design on wicket gate and runner blade servomotors should be considered.
- Generator capacity: A significant increase in turbine output can overload the generator. Generator capacity can usually be increased by rewinding. Also, many older generators were rated at 0.8 power factor, but operate at 0.95 to unity power factor. The higher power factor allows increased power output for the same kVA.

- If power output is increased, the capacity of the transformers, circuit breakers, bus/cable, etc. must be reviewed.
- An increase in turbine flow can affect hydraulic transients, increasing conduit pressure rise.

Size of Unit

The potential for turbine upgrade through runner replacement is closely related to the size of the unit through its relationship with costs.

For example, the costs of a 5-10 MW runner may be 1.5 to 2 times higher per MW than for a 50 MW unit. For units greater than 100 MW this difference would be compounded. Screening level runner costs for different types of turbines are provided in Section 6.

B1.1 Capacity

Indications of capacity improvements for turbine runners are particularly complex and can usually only be assessed on a site specific basis. Nevertheless, when runner replacements for other reasons are considered, increases in turbine output of 5-20% are not uncommon and can be justified on an economic basis.

Indicators to assess whether replacing the runner would likely allow increases in capacity output are based on questioning :

- Does the existing generator have at least a 5% higher output capability than the maximum turbine power possibly due to its own upgrading?
- Does the setting of the runner relative to tailwater level permit an increase of power of at least 10%.

If the answer to either questions is YES, it indicates that potential exists for modernization. This information will be summarized in Table 3-1, then used as input to Section 3 in Volume 1.

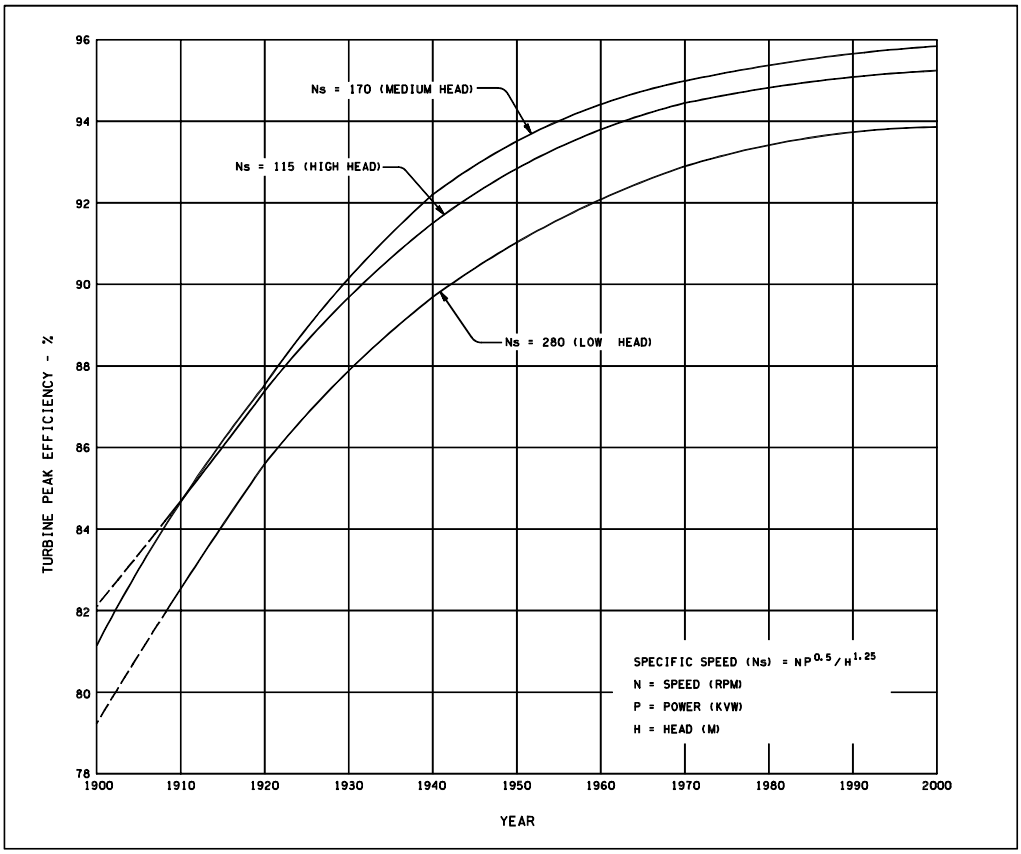

Figure 3-1
Francis Turbines
Efficiency Trends

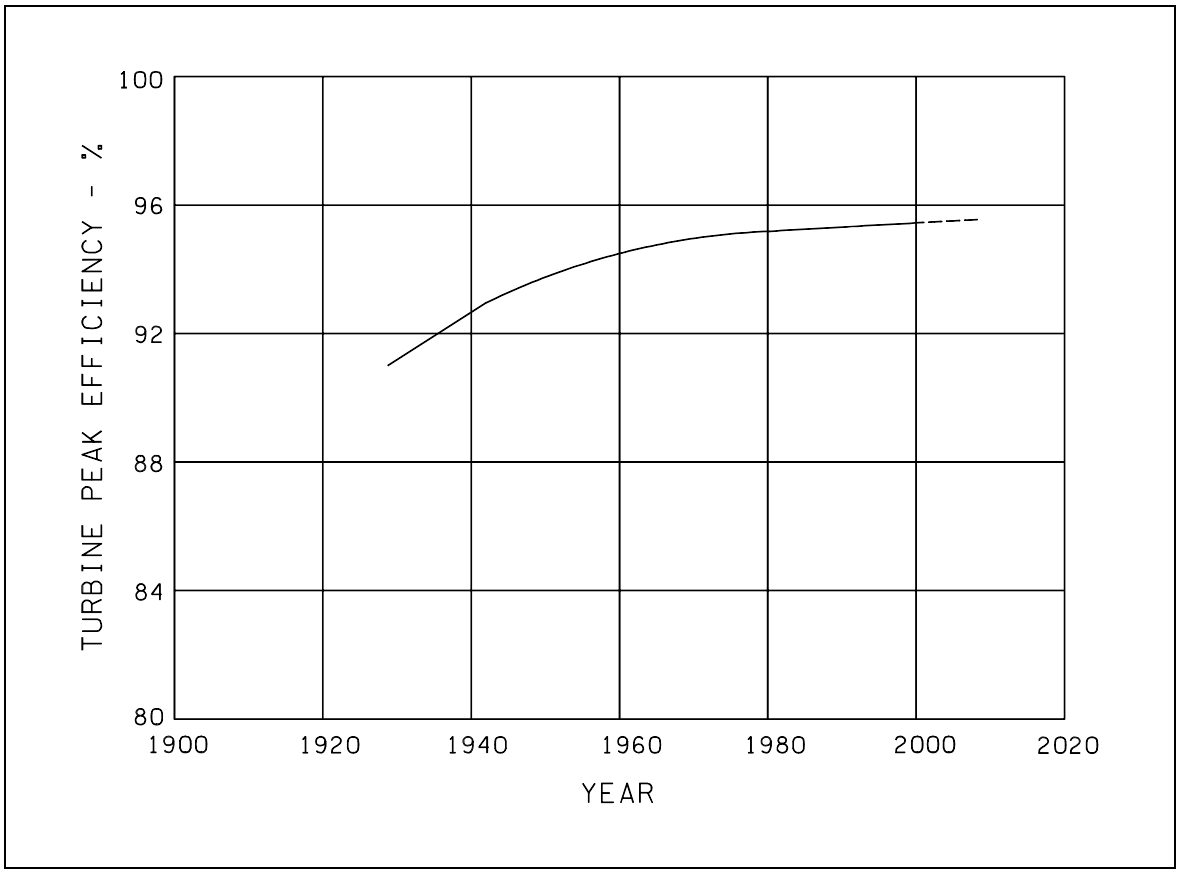

Figure 3-2
Kaplan Turbines
Efficiency Trends

B1.2 Efficiency and B1.3 Equipment

There are three main reasons why the efficiency of a unit may be substantially lower than its potential:

- The unit is old and in general, the efficiencies of modern turbines are significantly greater.
- The turbine runner has deteriorated with age and no longer provides its design output.
- The unit is not operated at its most efficient gate position.

Age of Unit

Figures 3-1 and 3-2 indicated that a modern turbine runner might be 4-5% more efficient than a 1930's vintage, but that only about 40% (or about 2% efficiency) could be recovered directly by a runner replacement.

Ageing of Unit

Discussion in Section 4 indicates that degradation of the runner of about 0.08% to 0.05% per year in terms of efficiency is a conservative estimate (i.e. for a 1930's plant, the degradation could be about 3.5% to 5%).

Unit Operation

The manner in which a unit is operated is an important consideration in determining runner replacement potential. If a unit is operated for long periods of time outside the areas of present maximum efficiency, a new runner with different efficiency characteristics should be investigated.

Indicators to assess whether replacing the runner would likely allow increases in efficiency and hence output are based on questioning:

- For a specific piece of equipment, and based on size of unit, does the potential efficiency gain (from tests or curves) and age exceed or equal, as appropriate, the numbers given in tabular form below:

Unit size	Efficiency gain from runner replacement that indicates feasibility	Age Indicator that indicates feasibility
<10 MW	>5%	>60 years
10-50 MW	3-4%	>45 years
50-100 MW*	2-3%	>30 years
>100 MW*	2%	>30 years

* Most utilities will already have undertaken some form of efficiency tests on units greater than 50 MW, both at the time of commissioning and recently if they are in the order of 30 or more years old.

If the answer in the table above is YES, this indicates that the potential exists for modernization. However, not withstanding the above, if the unit is run for more than 25% of its operating life at a gate opening less than 70% of best gate, the screening indicator suggests that turbine upgrading is not worth pursuing.

This information will be summarized in Table 3-1, then used as input to Section 3 of Volume 1.

B2.1 Range of Products

Indicators of flexibility for turbines and associated equipment are complex and can usually only be assessed on a site specific basis. Fundamentally, it is an assessment of whether the turbine and associated equipment is readily adaptable (flexible) to changed operating conditions and changed demands for product and services.

This would primarily relate to operating in zones and manners not originally designed for and could include:

- Operating beyond design full load output
- Operating in different load zones
- Significant variations in load
- More stopping and starting

Indicators for flexibility are based on questioning:

- Are there any proposed or necessary changes to unit operation that requires the turbine runner and/or any other associated equipment to be upgraded.
- Are there any significant improvements to the range of products from the unit that could be achieved by hydromechanical equipment upgrades.

If the answers to either question is YES, this indicates that there is potential for modernization. This information will be summarized in Table 3-1, then used as input to Section 3 of Volume 1.

Table 3-1
Hydromechnical Equipment
Summary of Screening Indicators

Project: _____
Equipment Name: _____
Asset No.: _____
Prepared by: _____
Date: _____

Is Life Extension Indicated by:			Is Modernization Indicated by:		
Dependability	Yes	No	Output	Yes	No
- Condition	❒	❒	- Capacity	❒	❒
- Performance	❒	❒	- Efficiency and Equipment	❒	❒
- Operational Risk	❒	❒			
- Cost*	❒	❒			
Comments:			Comments:		
Sustainability	Yes	No	Flexibility	Yes	No
- Environmental Issues	❒	❒	- Range of Products	❒	❒
Comments:			Comments:		

* including assessment of cost allocation criteria.

4
EVALUATIONS OF CONDITION AND PERFORMANCE

4.1 Introduction

Evaluation of plant condition and performance are key steps to successfully formulating a Life Extension and Modernization Plan (LEM Plan) as described in Volume 1, Section 4 of these guidelines. The evaluations discussed in this Volume rely mainly on using existing information and knowledge on the plant or new information that is inexpensive to obtain. The goal is to avoid extensive testing and analysis at this stage but still obtain a reasonable assessment of equipment condition. The Life Extension and Modernization process is iterative and life extension activities are identified in this first stage. Additional testing or studies may be justified once the LEM Plan is formulated and projects are more clearly defined. These further tests would be conducted as part of a future feasibility study (refer to Section 7 of this Volume).

Section 4 focuses on assessing the present condition and performance of the hydromechanical equipment, predicting its remaining life and identifying activities that will extend the life of the equipment. Timing aspects of the identified life extension activities are nominated and a schedule of activities is formulated. The assembled information from this section is used to develop tables of Needs and Opportunities (Tables 4-3, 4-4 and 4-5) in Volume 1, which are subsequently used to develop the LEM Plan. A periodic review of the overall process in Volume 2 is often useful. The following flowchart (Figure 4-1) describes how each of the sub-sections contribute to the identification of activities for the LEM Plan.

To conduct the condition assessment of each piece of equipment and identify life extension activities, an Equipment Condition Assessment Summary Sheet (Table 4-1) may be used for convenience, particularly for site visits, before inserting the information into the extensive tables in Volume 1. Based on the Asset Register (described in Volume 1, Section 4.2) assembled for the plant, a worksheet is prepared for each piece of mechanical equipment. This ensures that all required information for the LEM Plan projects is obtained at the overview level. This Section contains the technical information to assist in completing the worksheet. A similar table for modernization opportunities is completed using Section 5 of this Volume in particular.

To assist in following the process, a depiction of Table 4-1 is provided at the start of each sub-section. The highlighted portion indicates the part of the worksheet covered by information in the sub-section.

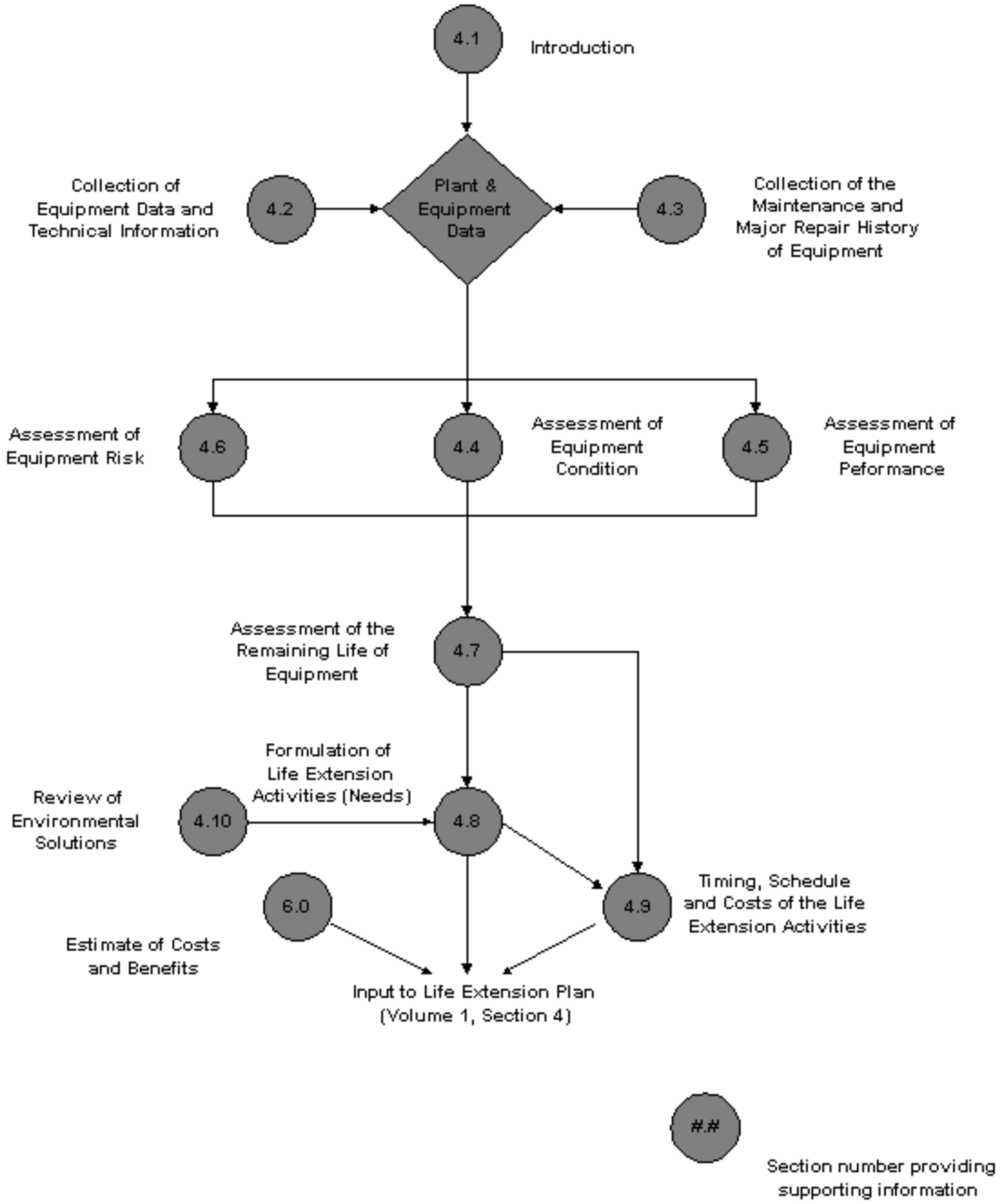

Figure 4-1
Input of Hydromechanical Equipment Data to Life Extension Plan

Table 4-1
Site Worksheet for Equipment Condition Assessment
Identification of Needs

Plant: _____
Equipment Name: _____
Unit No.: _____
Asset No.: _____
Prepared by: _____ **Date:** _____

Equipment Data and Technical Information (Section 4.2)	**History of Maintenance and Major Repairs** (Section 4.3)
Condition Assessment of Equipment (Section 4.4)	**Performance and Operational Information** (Section 4.5)
Risk Evaluation (Section 4.6)	**Assessment of Remaining Life** (Section 4.7)

Condition Rating (if available) (Section 4.4)	**Repairability Rating** (Table 4.4, Section 4.4)	**Environmental Issues** (Section 4.10)

Possible Life Extension Activities (Section 4.8)	**Timing and Costs of Life Extension Activities** (Section 4.9)

4.2 Equipment Data and Technical Information

<table>
<tr><td colspan="2">Equipment Data and Technical Information (Step 4-2, Volume 1)</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
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</table>

The checklists provided in Sections 4.3, 4.4 and 4.5 provide a summary of the technical data and background information required to conduct a general condition assessment of the main mechanical equipment.

Desk-top Review

In assessing the present condition or performance of the plant's hydro mechanical equipment, it is necessary to begin with the key technical data which describes the existing equipment. This technical data includes nameplate, original design, existing output, efficiency or index test, and equipment, data, records and reports. This information is input into Table 4-1 or directly into Table 4-3 and 4-4 of Volume 1, Section 4.2.

Design and performance data for the original turbine are usually available in the procurement specifications, the O&M instructions, unit performance curves, and commissioning test results. A review of the available records can assist the user in determining the turbine characteristics, i.e. head, output, speed, and efficiency at rated output, in addition to the turbine peak efficiency. The records will likely reveal the range of operating net heads and associated outputs.

The data obtained from existing records is not always reliable since changes in the operating conditions or unit design may have occurred. While existing information from records may not provide accurate information on current operation, in most cases it will indicate the potential performance level achievable by rehabilitating the turbine to the like-new condition. Similarly, commissioning tests of old units will likely not reflect the existing condition of the unit; more recent test results will be valuable. Undertaking new tests may be a costly exercise beyond the scope of an overview level review.

Typical sources of general plant data and equipment information are:

- Drawings (plant layout and mechanical) - original as-builts and updated revisions
- Engineering study reports for original design
- Feasibility studies for original design or upgrades
- Inspection reports of condition and performance
- Environmental study reports

- Seismic evaluations
- Local Operating Orders
- System Operating Orders
- Operations reports
- Operating logs
- Technical data books
- Investigations into equipment deficiencies
- Commissioning results and reports
- Site test results and reports
- Operations & maintenance manuals

Site Visit

The purpose of a site visit is to verify, where possible, all information obtained from the desk-top review of the plant equipment. This includes verifying that the asset register is complete and checking nameplate data to ensure that all recorded technical information is correct. Section 4.3, Volume 1 provides some additional guidance on the objectives of the site visit.

Site personnel are often the greatest source of information, particularly when records of equipment and plant operation changes are unavailable or unorganized. Key personnel who can assist in verifying information obtained from the records include:

- Station Manager
- Maintenance managers, superintendents, area leads
- Plant operators
- Previous project managers for specific plant work
- Environmental coordinator
- Station business manager
- "In-house" engineering department technicians and engineers
- Consultants in specific cases
- Manufacturers and suppliers

4.3 History of Maintenance and Major Repairs

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs (Step 4-3, Volume 1)</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
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<tr><td>Condition Rating (if available)</td><td>Repairability Rating</td><td colspan="2">Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

Table 4-2 is an equipment specific checklist of maintenance and repair work that can form part of an equipment's repair history. It should be used as a check that a complete maintenance and repair history for the equipment has been captured.

A review of the maintenance and repair history of the equipment and future plans is an important step in assessing equipment condition and predicting remaining life. Initially, the following reports should be obtained for the review, if available:

- Annual station reports or year-end summaries for maintenance and capital projects undertaken
- Station maintenance logs
- Operating & maintenance (O&M) annual plans and budgets for upcoming years
- Annual capital project plans and budgets for upcoming years

Using the above reports, the following questions about specific equipment should be addressed:

1. What is the trend in maintenance requirements (costs, hours, downtime, etc.) for the equipment over the years? Is it increasing? Constant? This information should give an indication of deteriorating condition. A chart of annual maintenance and capital costs broken down into the major equipment categories is extremely useful and is worth preparing.

2. Are there chronic problems with the equipment and what are the problems?

3. Does the equipment seem to be a high consumer of maintenance labour and budget?

4. Where is the equipment in its life cycle?

5. Has the level of maintenance been sufficient?

6. Has the maintenance been superficial in addressing the symptoms rather than the causes of high maintenance?

7. What major repairs have been done on the equipment and did these repairs substantially improve the life expectancy of the equipment? What was the level of rehabilitation?

Table 4-2
Maintenance and Major Repair History of Hydromechanical Equipment

Asset No.	Equipment	Maintenance & Major Repair Checklist (i.e. Have any of the following been done or occurred?)
1.1.1.1	Turbine (General)	• Re-painting/re-coating or surface roughness improvement (to reduce friction losses). Specific activities may include patch ups, overcoating, stripping and painting. • Welding on water passages. • Vibration monitoring system installation or upgrades. • Control scheme improvements to avoid rough zones. • Tripod removal or other modifications to increase unit efficiency. • Air injection or water injection through headcover, bottom ring, or in draft tube (spears, tripods, cross pipes, etc.) to reduce vibration in rough zones or decrease overall unit roughness. • Seal water improvements to lengthen life of seals (for synchronous condense operation).
1.1.1.2	Runner	• Cavitation, erosion and crack repair -Annual welding ($/yr, labour hours/year). • Re-coating with different materials to prevent cavitation and/or erosion (using very hard metals, polymeric coatings, ceramics). • Runner modifications to reduce cavitation. • Runner wear ring replacement. • Runner replacement with like for like runner or new runner design.
1.1.1.3	Wicket Gates Wicket Gate Operating Mechanism	• Refurbishment or replacement of the wicket gates. • Replacement of bushings. • Change of bushing type/design (eg. from greased to greaseless, etc.). • Change of wicket gate seal type (high density polyurethane, etc.) or replacement of seals due to excessive leakage or rubbing. This can apply to inter-gate seals or head cover and bottom ring seals. • Replacement of V packing on lower headcover bearings. • Improvements to failure mechanism to increase reliability. • Rehabilitation of operating ring, links, levers and servomotor connecting rods. • Implementation of an automatic greasing system. (Parallel or indexed.)
1.1.1.3/5	Pelton Nozzle Assemblies and Deflectors	• Replacement of nozzles or needle tips. • Replacement of deflectors. • Repair of nozzles or needle tips. • Repair of deflectors. • Repair of deflector/needle servomotors. • Replacement of deflector/needle servomotors.

Asset No.	Equipment	Maintenance & Major Repair Checklist (i.e. Have any of the following been done or occurred?)
1.1.1.4	Turbine Guide Bearings	• Work done to minimize vibration levels (oil viscosity, etc.). • Bearing wipes. • Replacements, upgrades and/or maintenance of protection instrumentation. • Improvements carried out to reduce water usage, leakage, and lower running temperatures. • Pump replacements. • Purchase of replacement bearings for stores to reduce downtime after a failure. • Improvements to filtering system. • Replacement of heat exchangers.
1.1.1.4	Turbine Shaft and Shaft Seal	• Repairs on seal wear surface • Re-machining of journal • Realignments
1.1.2.1	Governor Hydraulics	• Replacement of pressure accumulators. • Replacement of pumps. • Improvement of oil filtering (i.e. installation of kidney filters). • Replacement of hydraulic system components. • Change of oil system to a high pressure system. • Addition or replacement of make-up air compressors. • Replacement or upgrading of instrumentation. • Addition of standby or jockey pumps to improve reliability/cycle time. • Rehabilitation or replacement of distributing valves.
1.1.2.2	Governor Control System	• Governor upgrades (e.g. to digital or PLC type governor). • Replacement of control components and circuitry. • Obsolescence (parts availability)
1.1.3	Turbine Inlet Valve (TIV)	• Re-painting or re-coating. • Adjustment or replacement of main seals. • Replacement of bearings. • Replacement of shaft seal. • Replacement of actuator. • Replacement of valve

4.4 Condition Assessment of Equipment

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment (Step 4-3, Volume 1)</td><td colspan="2">Performance and Operational Information</td></tr>
<tr><td colspan="2">Risk Evaluation</td><td colspan="2">Assessment of Remaining Life</td></tr>
<tr><td>Condition Rating (if available) (Step 4-3, Volume 1)</td><td>Repairability Rating (Step 4-3, Volume 1)</td><td>Environmental Issues</td><td></td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

While plant performance is the fundamental criterion for evaluating the existing plant , the condition of the plant and the possible future effects of its condition on operating capability, downtime, and reliability are also significant factors in assessing the equipment needs and modernization opportunities. The condition of the critical hydromechanical components (noted in Table 4-3) may have deteriorated to such a degree that they are approaching the end of their useful lives, necessitating repair or replacement. Section 4.4 discusses the critical hydromechanical components, methods to assess the components' condition, and criteria to determine whether repair is necessary. Section 4.8 describes the life extension activities that could be implemented based on the outcome of the condition assessment.

The Equipment Condition Assessment Summary worksheet for each piece of equipment (Table 4-1), sometimes referred to as the "site worksheet", may be a convenient way to collect information, particularly during the site visit. Alternatively, information can be entered directly into Table 4-3 of Section 4, Volume 1.

Table 4-3 in this section provides the summary of the technical data requirements, typical assessment parameters and common life extension activities for each type of mechanical equipment. The supporting text of Section 4.4 provides detailed information on the items covered in Table 4-3. Table 4-4 provides a rating system for the assessment of equipment repairability as discussed in Section 4.4.1.

Table 4-5 provides typical values of some condition assessment parameters. It should be used as a general guide to the condition of the equipment. When a particular condition assessment parameter exceeds the criteria stated in Table 4-5, further investigation of equipment condition and performance is advised.

Plant operational data is also important background information for assessing equipment condition. Table 4-9 in Section 4.5 summarizes the operational parameters of interest. Assessment of Condition (Section 4.4) and Performance (Section 4.5) are usually done in parallel.

4.4.1 Condition Rating System

The evaluation of equipment condition (its wear and deterioration) is, in part, a subjective evaluation often based on the experience and expertise of the expert. A condition rating system is usually developed to provide an objective means of evaluating equipment condition, although some subjectivity, more appropriately called "engineering judgment", is always a component. Further development of probable life and life expectancy curves, correlated to equipment age and condition, are tools that can be used for recommending life extension activities or equipment replacement once the equipment condition has been established.

Section 4.4 provides detailed instructions on condition and performance information that should be gathered and the criteria/indicators that are useful for assessing equipment condition. The information obtained on equipment condition can be fed into a condition rating system process, if necessary, or used on its own.

The Repair, Evaluation, Maintenance and Research Program (REMR), developed by the US Army Corps of Engineers, is one of the more developed condition rating systems available in the public domain. It contains useful information for most types of hydro plant equipment.

The REMR Condition Index Scale establishes a standard definition of condition. It uses a numerically-based scale, extending from 0 to 100. Measurement of condition is accomplished by using clearly defined condition indicators. These condition indicators are usually either test results from standard tests or visual or other non-destructive examinations that give an indication of current condition.[9] The condition rating obtained by using REMR or another condition rating system should be entered into the Equipment Condition Assessment Summary worksheet (Table 4-1) in Section 4.1 for each piece of equipment so that the condition rating is put into context with other information obtained on maintenance history, performance and condition.

REMR worksheets for mechanical equipment are provided in Appendix D to assist with the collection of condition assessment data. The complete REMR guidelines can be obtained from the US Army Corps of Engineers if the REMR rating system along with these Guidelines are used for the condition assessment. The Corps is planning to update the REMR guidelines in the Year 2000.

The use of REMR gives a snapshot look and a standardized evaluation of a plant. Many companies and utilities have their own "in-house" condition rating systems which can be used in lieu of REMR.

[9] US Army Corps of Engineers, March 1993, "*The Repair, Evaluation, Maintenance and Research Program (REMR)"*

With any condition rating system, there are a number of issues that need to be considered carefully before using the system in its entirety:

1. Condition indices are a tool to help estimate the remaining life of equipment. Service life, however, is not necessarily the same as useful life. Many types of equipment are replaced for reasons other than condition. The concept of "remaining life" for equipment is discussed in Section 4.7.

2. The usefulness of certain tests and inspections "required" by the condition rating system's methodology should always be evaluated. Existing test reports, where available, should usually be relied upon at this level of assessment. Often the test procedures suggested are cited to trigger an investigation into whether or not data on certain condition indicators exist but the cost of extensive tests are probably not justified at this level of review.

3. The concept of "end of service life" for many types of mechanical equipment is difficult to apply. Diligent maintenance and periodic overhauls can keep equipment functional indefinitely. Although maintenance costs increase and obsolescence of parts can be a problem, replacement can rarely be justified on reduced maintenance costs alone. Therefore, the use of condition ratings to predict end of service life may not always be justified.

4. In many condition rating systems, the overall condition rating assigned to a piece of equipment, such as the turbine, is the condition rating calculated for the component in the worst condition (i.e. the component with the lowest condition rating). The objective of this method is to flag equipment that has a component in very poor condition. However, the condition rating index does not provide an indication on the repairability of the component. Equipment may be in very poor condition but easily repairable with low cost and resource requirements. A second rating system based on repairability is often required to complement the condition rating index. Table 4-4 provides a preliminary repairability rating system.

Table 4-3
Condition Assessment of Equipment

Use the following assessment parameters in combination with information obtained from the maintenance and major repair history review. A table of criteria that can be used for the condition assessment is provided in Table 4-5.

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
1.1.1.1	Turbine (General)	• Age • Type (Francis, Kaplan, etc.) • Rated output • Maximum Output • Rated speed • Rated net head • Maximum net head • Maximum turbine efficiency at rated head • Discharge at rated output • Pump efficiencies at rated pump head (for pump turbines)	• Level of cavitation pitting, erosion and corrosion damage • Levels of cracking • Vibration levels • Rough zones • Annual outage time • Maximum output vs rated • Condition of seals (if applicable) • Structural integrity • REMR Rating • Annual maintenance/ service ($/yr) • Current efficiency vs. original efficiency <u>Francis, Kaplan & Pump Turbines:</u> • Surface condition of spiral case or distributor (coating) • Condition of baffle plates • Structural integrity of stay vane fillets	• Replace entire turbine • Rehabilitate entire turbine to original service level • Re-painting/re-coating • Seal leakage improvements • Welding <u>Francis, Kaplan & Pump Turbines</u>: • Refurbish or replace wear (seal) rings <u>Kaplan/Propeller:</u> • Refurbish discharge ring

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
			Pelton: • Condition of housing • Condition of inlet piping	
1.1.1.2	Runner	• Type • Age • Diameter • Weight • Material • Original surface finish (rms) • Original runner seal or tip (Kaplan/Propeller) clearances	• Surface finish (rms) • Runner seal or blade tip clearance (gap) • Level of cracking • Level of cavitation (lbs/8000 hrs) • Level of erosion damage • Annual welding ($/yr, labour hrs/yr) • Structural integrity • REMR Rating Kaplan Specific: • Blade movement (condition of blade mechanism and bearings) • Condition of blade servomotor • Servomotor pressure • Servomotor leakage rate Pelton Specific: • Erosion/corrosion of bucket surfaces • Minimum bucket wall thickness • Bucket splitter width • Cracking in bucket root area • Condition of bucket bolts	• Cavitation & erosion repair (welding) • Re-coating to prevent cavitation, erosion and corrosion • Replace due to end of service life with identical runner • Reprofile blades Kaplan Specific: • Weld-up runner blades so that they are fixed in one position • Replace blade trunnion bearings • Repair/replace blade servomotors Pelton Specific: • Replace bucket bolts • Repair buckets by welding and grinding

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
1.1.1.3	Wicket Gates, Wicket Gate Operating Mechanism	• Age • Bushings types (greased, greaseless, etc.) • Design diametrical clearance of bearings/bushings) • Seal type (eg. High-density polyurethane) • Wicket gate original surface finish (rms) • Type of failure mechanism (shear pins, etc.) • Servomotor stroke at maximum output • Maximum servomotor stroke	• Intergate leakage • Surface finish of wicket gates (pitting) • Level of cracking • Other structural damage • Bushings/bearings condition • Radial clearance of bearings • Seal condition • Nose to tail seal clearances • End clearances • History of failure mechanism (e.g. shear pin failures) • Condition of wear surfaces on wicket gate links, levers and connecting rods • Servomotor leakage rate • Servomotor pressure • Annual maintenance/service ($/yr) • Obsolescence, parts availability • REMR Rating	• Refurbish or replace (re-cast or re-fabricate) gates • Refurbish gate stem bearing areas • Replace bushings • Replace seals due to excessive leakage or rubbing • Painting and filling voids to improve surface finish • Welding or metal spray to improve surface finish • Replace/refurbish servomotors

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
1.1.1.3/5	Nozzle Assemblies, Deflectors and Operating Mechanisms (Pelton turbines)	• Type/design of injectors (internal or external servomotors) • Age	• Servomotor (needle) leakage rate • Servomotor (needle) pressure (% governor pressure) • Surface finish or erosion damage to needle tip, nozzle and nozzle seat ring • Leakage when closed • Condition of bushings on deflectors • Surface condition of deflectors • REMR rating • Estimated efficiency losses due to nozzles • Condition of deflector servomotor • Annual maintenance/service ($/year) • Obsolescence, parts availability	• Refurbish or replace servomotor • Repair or replace needle tip, nozzle or nozzle seat ring of nozzle assemblies • Replace nozzle assemblies • Use coatings to reduce cavitation, corrosion and erosion damage • Repair or replace deflectors • Replace bushings on deflector mechanism
1.1.1.4	Turbine Guide Bearing and Lube System	• Age • Bearing type • Manufacturer • Lube system type (self-pumping, forced, external, water-cooled heat exchanger) • Design maximum bearing metal temperature • Design maximum bearing oil temperature • Design radial clearance • Type & level of sophistication of protection instrumentation	• Bearing metal temperatures • Bearing oil temperatures • Radial clearance • Shaft runout • Level of surface damage on babbit • Discolouration of babbit • Bonding of babbit to bearing shell • Oil samples • Leakage • Condition of protection instrumentation • Annual maintenance ($/yr) • No. of protection trips/yr • REMR Rating	• Replace protection instrumentation due to end of life or obsolescence. • Replace pumps. • Replace worn hydraulic parts. • Scrape or machine bearing surface • Replace piping and/or valves • Improve filtering to extend life. • Replace heat exchanger • Re-babbit

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
1.1.1.4	Turbine Shaft and Shaft Seal	• Diameter • Material • Original surface finish of bearing journal (rms) • Original surface finish of shaft seal wear surface - shaft sleeve (radial seal) or horizontal plate (axial seal) (rms).	• Roundness • Bearing journal surface finish (rms) • Surface finish of shaft seal wear surface (rms) • Level of cracking	• Re-machine journal • Re-align • Repair shaft seal wear surface • Replace shaft seal wear surface • Replace seal with new design • Replace traditional stuffing box seals (graphite packing) with seals utilizing plastic wearing surfaces
1.1.2.1	Governor Hydraulics (High pressure oil system and distributing valves)	• Governor type • Manufacturer • Working pressure • Age • Accumulator size • Number, type and size of pumps	• Sufficient regulating capacity • Pump condition • Oil pump cycling time • Oil analysis • Make-up air cycling time • Rate of wear on parts • Outages/trips annually • REMR Rating • Reliability – standby pump? • Annual maintenance ($/yr) • Obsolescence <u>Kaplan & Pelton Specific:</u> • Sufficient regulating capacity for adjustable blades (Kaplan) or nozzle assemblies (needles)	• Refurbish • Replace hydraulic system components. • Replace make-up air compressor • Replace instrumentation • Rebuild pilot main distributing valves • Replace existing governor with new electro-hydraulic governor • Convert mechanical governor to electro-hydraulic governor • Replace governor with a digital governor • Replace governor with a gate positioner

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Possible Routine Life Extension Requirements
1.1.2.2	Governor Control System	• Type • Manufacturer • Age	• Speed regulation performance • Unit power output stability • Reliable turbine shutdown • Sufficient regulating capacity • Condition of instrumentation • Condition of principal circuits (speed sensing and regulations, PID control, etc.) • Condition of main overspeed and speed switches • PMG/ballhead motor vibration • Reliable monitoring of governor operation • Condition of wicket gate feedback linkage • REMR Rating • Obsolescence	• Replace control components and circuitry • Re-magnetize PMG • Rebuild ballhead motor • Rebuild pilot/main distributing valves • Rebuild wicket gate feedback linkage
1.1.3	Turbine Inlet Valve	• Type (butterfly, spherical, etc.) • Actuator type (electric, oil or water, etc.) • Age • Head loss • Bypass system details (manual/automatic)	• Leakage rate • Head losses (if known) • Condition of bearings/trunnions • Shaft packing/seal condition • Reliability of actuator (emergency closure) • Changes in opening/closing force requirements • Vibration levels during valve operation • Bypass condition • Coating condition - level of corrosion or erosion damage • REMR Rating	• Re-paint or re-coat • Replace bearings • Replace shaft packing/seals • Provide automatic bearing lubrication • Adjust main seal • Replace main seal • Replace valve • Replace actuator • Replace controller

Table 4-4
Equipment Repairability Rating System

Rating	Repair Characteristics
Good	• Technical complexity: Easy • Testing: Extensive testing or investigation is not required. • Replacement parts: Readily available and repair does not require the replacement of any major components. • Cost: Cost of parts and labour easily justified by restoration of equipment performance and avoidance of replacement costs • Outage time: Does not affect total plant outage time or the increased outage time has no economic impact on the plant, (examples, 1. there is no water available or water can be stored during the extended outage; 2. power is inexpensive so revenue losses are very low.) • Deficiencies: Repair would completely solve or mitigate the condition or performance deficiency for a number of years. • Operations: No further limits on operation result from the repair. • Access: Parts easily accessible or repair can be done in-situ.
Moderate	• Technical complexity: Moderate. Extensive testing or investigation is not required but some engineering is required. • Replacement parts: Available and repair does not require the replacement of major components. • Cost: total cost of parts and labour is moderate but cost of repair over the next few years can be justified by the avoided replacement cost. • Outage time: Increases total outage time but plant economic impact of extended outage is low. • Deficiencies: Repair would completely solve or mitigate the condition or performance deficiency for a number of years. • Operations: No further limits on operation result from the repair. • Access: Parts accessible or repair can be done in-situ.
Fair	• Technical complexity: Difficult. Extensive testing, investigation and engineering (design) required. • Replacement parts: Available but expensive; or obsolete but can be custom made. • Cost: Expensive. Total cost of parts and labour is high but replacement is even more uneconomic. Economic justification of the repair is difficult but it may be the only technical alternative other than replacement. • Outage time: Greatly increased by repair requirements; or even a small extension of the outage time means high revenue losses. There is a significant economic impact on plant. • Deficiencies: Repairs would only partially or temporarily solve/mitigate the condition or performance deficiency. Increasingly expensive repairs would be required over the years to avoid replacement. • Operations: New restrictions on operation because deficiencies are only partially repaired (e.g. some cavitation repair work such as runner blade reprofiling may result in a new rough zone for the unit). • Access: Parts difficult to access and must be removed for repair (example: stainless steel runners must be removed for heat treatment).
Not repairable	• Technical complexity: For technical reasons, equipment cannot be repaired (e.g. runner made of non-weldable material such as cast iron). • Replacement parts: Not available (obsolete) and cannot be made. • Deficiencies: Deficiencies cannot be solved or mitigated (e.g. cause of unit rough zones cannot be identified).

Table 4-5
Guidelines for Assessing the Condition of Critical Turbine Components

Component	Condition	Criteria
Runner	Cavitation	Francis and Pump Turbines (only an initial guideline): Stainless steel: $0.1D^2$ lb/8000 hrs ($0.5D^2$ kg/8000 hrs) Carbon steel: $0.15D^2$ 1b/8000 hrs ($0.75D^2$ kg/8000 hrs) D=runner outlet diameter
		Kaplan (only an initial guideline): Stainless steel: $0.15D^2$ lb/8000 hrs ($0.75D^2$ kg/8000 hrs) Carbon steel: $0.2D^2$ lb/8000 hrs ($1.0D^2$ kg/8000 hrs)
		Pelton (only an initial guideline): $0.1D^2$ lb/8000 hrs ($0.5D^2$ kg/8000 hrs)
		Depth - 1/8 in. (3 mm) per year
		Repair damage equal to twice the above
	Seal or tip clearance	2 times design or >1/4 in (6 mm).
	Cracking	Monitor >1/2 in. (12 mm) Repair >2 in. (50 mm)
Wicket Gate	Leakage	>1% Maximum Discharge
		Unit Creep when brake released; difficulty stopping
	Average Clearance When Closed	Nose to tail >0.020 in (0.5 mm) End >0.10 in (2.5 mm)
	Pitting	Depth >3/16 in.
	Cracking	Depends on the number and location of cracks - usually cracks are on the stems
Wicket Gate Bearings	Clearance (radial)	>3 x design value >0.060 in. Maximum (1.5 mm)
Servomotor	Pressure	<95% Governor Pressure
	Oil Pump Cycling Time	>30 minutes at steady load. However, this does not mean that the servomotor is necessarily worn.
Turbine Shaft and Shaft Seal	Cracks	Crack free
	Bearing Journal Finish	>63 micro in. (1.6 :m)
	Shaft Seal Wear Surface	Surface finish deterioration, and seal adjustment every 6 months or replace every 5 years
Guide Bearing	Babbit	Crack free No discolorations
	Temperature	>60°C (140°F) and increasing trend
	Clearance (Redial)	>2 x design value >0.010 in. (0.25 mm) maximum
	Runout	Within Standard such as CEA's "Guide for Erection Tolerances and Shaft Alignment" or ORGRES Standards
Governor	Speed Control	As per IEEE Standard 125 and standards of the local power system authority.
	Power Output	As per IEEE Standard 125 and the standards of the local power system authority.

Component	Condition	Criteria
Turbine Inlet Valve	Leakage	Butterfly Valve: Comparison between typical new and used condition valves - New condition: 0.005 cu ft/min per ft of valve diameter 0.05P/min per m of valve diameter - Used condition: 0.02 - 0.03 cu ft/min per ft of valve diameter 2.0 - 3.0P/min per m of valve diameter
		Spherical Comparison between typical new and used condition valves - New condition: Few drops. - Used condition: 0.02 cu ft//min per ft of valve diameter 2.0 P/min per m of valve diameter

Example of How to Use Tables 4-3, 4-4, 4-5 and 4-9

The following are the general steps for using Tables 4-3, 4-4, 4-5 and 4-9 in the condition assessment of wicket gates.

1. Refer to Table 4-3. Look under 1.1.1.3, the asset number for wicket gates and the wicket gate operating mechanism.

   (a) Collect the following information and data on the wicket gates as identified in Table 4-3.

   - age
   - bushing type
   - design radial clearance of bushings
   - seal type
   - wicket gate original surface finish

   (b) Review relevant unit performance information as outlined in Table 4-9 of Section 4-5 as a background for the condition assessment.

   (c) Inspect the wicket gates if possible, review past maintenance and inspection records and interview site maintenance and operations personnel to obtain information on the following assessment parameters identified in Table 4-3 (Asset Number 1.1.1.3):

   - surface finish of wicket gates
   - level of cracking
   - other structural damage

- radial clearance of bushings
- seal condition
- nose to tail seal clearances
- end clearances
- reliability of failure mechanism
- annual maintenance/service ($/year)

2. Refer to Table 4-5. Compare the data obtained in Step 2(c) above for the condition assessment parameters with the criteria in Table 4-5 for:

   - leakage
   - average seal clearances
   - pitting
   - cracking
   - radial bushing clearances

   Further investigation of condition or performance issues may be warranted based on the results. A condition assessment statement by the assessing engineer is made and the relevant information is entered into the site worksheet (Table 4-1).

3. Refer to Table 4-3. Based on the condition assessment of the wicket gates, life extension alternatives should be considered. Table 4-3 provides an overview level summary of the options available. The text of Section 4.8 provides more specific details.

   Life extension options for the wicket gates include:

   - refurbish or replace gates
   - refurbish wicket gate stem bearing areas
   - replace bushings
   - replace seals due to leakage or excessive rubbing
   - paint or fill voids to improve surface finish
   - weld or metal spray to improve surface finish

4. Refer to Table 4-4. Assess the repairability of the wicket gates using the life extension options selected.

   All the information collected above should be collected using the site worksheet (Table 4-1).

Safety

Overall plant safety regulations should be followed during the inspections and ground fault detectors are necessary in the power supply to the turbine water passages. Alternatively, a low voltage direct current power source should be used. Confined space requirements should also be ascertained before entry to the turbine water passages.

Terminology

Appendix E to Volume 2 provides a glossary of terms and descriptive figures for the main turbine components.

Oil Leakage

Turbine oil leakage can have serious consequences if pathways exist to release the oil to the environment. Many utilities and regulatory authorities have a zero-tolerance policy for oil leakage into the outside environment. Depending on the jurisdiction or licensing requirements of a particular area, the level of "acceptable" oil loss to the environment varies greatly.[10]

As an example, REMR's rating system for environmental and nuisance oil loss is provided in Appendix D with the other mechanical equipment REMR worksheets. Any oil leakage should be contained in a sump and then pumped through an oil water separator before being discharged to the environment.

Acceptable oil leakage is difficult to quantify. Even though significant oil leakage may still be within the REMR "acceptable" levels for a large plant, owners and operators may have much stricter criteria.

4.4.2 Turbine Runners

Inspections and tests for assessing the condition of a turbine runner cover the following areas:

- Cavitation damage
- Erosion and corrosion damage
- Cracking
- Seal/blade tip clearance
- Surface condition - rusting, surface profile

[10] US Army Corps of Engineers, March 1993, *"The Repair, Evaluation, Maintenance and Research Program (REMR)"*

Not every inspection and/or test procedure may be applicable or necessary in every case. The areas covered, however, allow a thorough assessment of the runner condition. Previous inspection reports and equipment studies should be used to minimize the resources required for the condition assessment at this stage.

Cavitation Damage

There is no strict definition of an "acceptable" level of cavitation before runner replacement is required. The concept of "too much cavitation repair" is really a function of costs i.e. repair costs and outage losses vs. the cost of a new runner. At some installations, runners are relatively inexpensive to replace and the philosophy is to let the runner cavitate to failure. Other runners can be repaired every year with minimal costs associated with the outages. In fact, the justification for replacement is usually based on efficiency upgrades and not cavitation issues. Some guiding principles on the assessment of cavitation are provided in this Section.

Turbine runner repair or replacement may be required if the corrosion, erosion, or cavitation damage to the runner is excessive. Cavitation damage to the runner:

- decreases efficiency
- increases operating stresses, and
- increases the downtime needed for repair.

Since cavitation damage often increases at an accelerating rate, repair is needed on a scheduled basis. Severe cavitation can initiate turbine hydraulic vibration, which increases stress and fatigue levels and can result in load restrictions placed on the unit.

Cavitation can be determined by the quantity of cavitation damage to the runner. The trend in new turbine contracts is towards "zero cavitation" guarantees. Higher efficiency and lower levels of cavitation in modern turbines are the result of advances in design using numerical methods and computational fluid dynamics (CFD). Although no standard exists for an acceptable level of cavitation, the following cavitation guarantee values provide an initial guideline.

		Excessive Runner Weight Loss due to Cavitation; lb (kg) per Operating Hour
Francis and Pump-Turbine Runners		
Stainless Steel	$0.1(D)^2 / 8{,}000$	$(0.5D^2/8000)$
Carbon Steel	$0.15(D)^2 / 8{,}000$	$(0.75D^2/8000)$
Kaplan Runners		
Stainless Steel	$0.15D^2 / 8{,}000$	$(0.75D^2/8000)$
Carbon steel	$0.2D^2 / 8{,}000$	$(01.0D^2/8000)$
Pelton Runners	$0.1D^2/8000$	$(0.5D^2/8000)$

Where D = runner outlet diameter or tip diameter, ft (m)

In addition, cavitation pitting depth greater than 1/8 inch (3 mm) per year over an area no greater than 4 sq. inches (25 cm^2) should be considered excessive.

A detailed assessment of cavitation, its effects, strategies for minimizing the effects and other related information can be found in Cavitation Pitting Mitigation in Hydraulic Turbines, prepared by Acres International Corporation, EPRI Report No. AP-4719 August 1986. The following material draws heavily from this report.

Cavitation Damage Inspection

Cavitation damage inspection should be made from both the draft tube area below the runner and from the stay ring/wicket gate area in the spiral (or semi-spiral) case.

The inspection should be thorough, covering not only the runner, but the draft tube liner, discharge ring, wicket gates, bottom ring, and headcover. The runner blades should be permanently numbered. The wicket gates may be identified by referencing them to the baffle vane. Typical cavitation pitting areas for Kaplan, Francis and Pump-Turbines are shown on Figures 4-2 to 4-7.

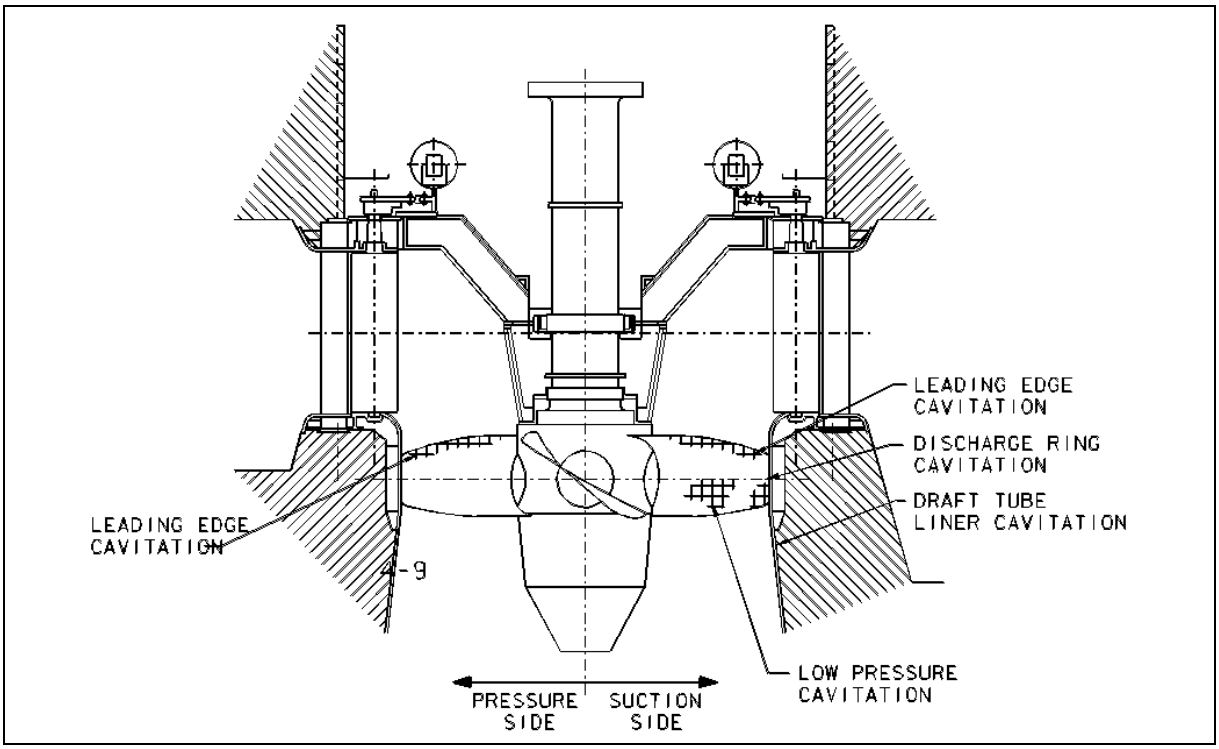

Figure 4-2
Typical Areas of Cavitation Pitting
Kaplan and Propeller Turbines - Reproduced from Cavitation Pitting Mitigation in Hydraulic Turbines, prepared by Acres International Corporation, EPRI Report No. AP-4719, August 1986, Volume 1, p. 4-9.

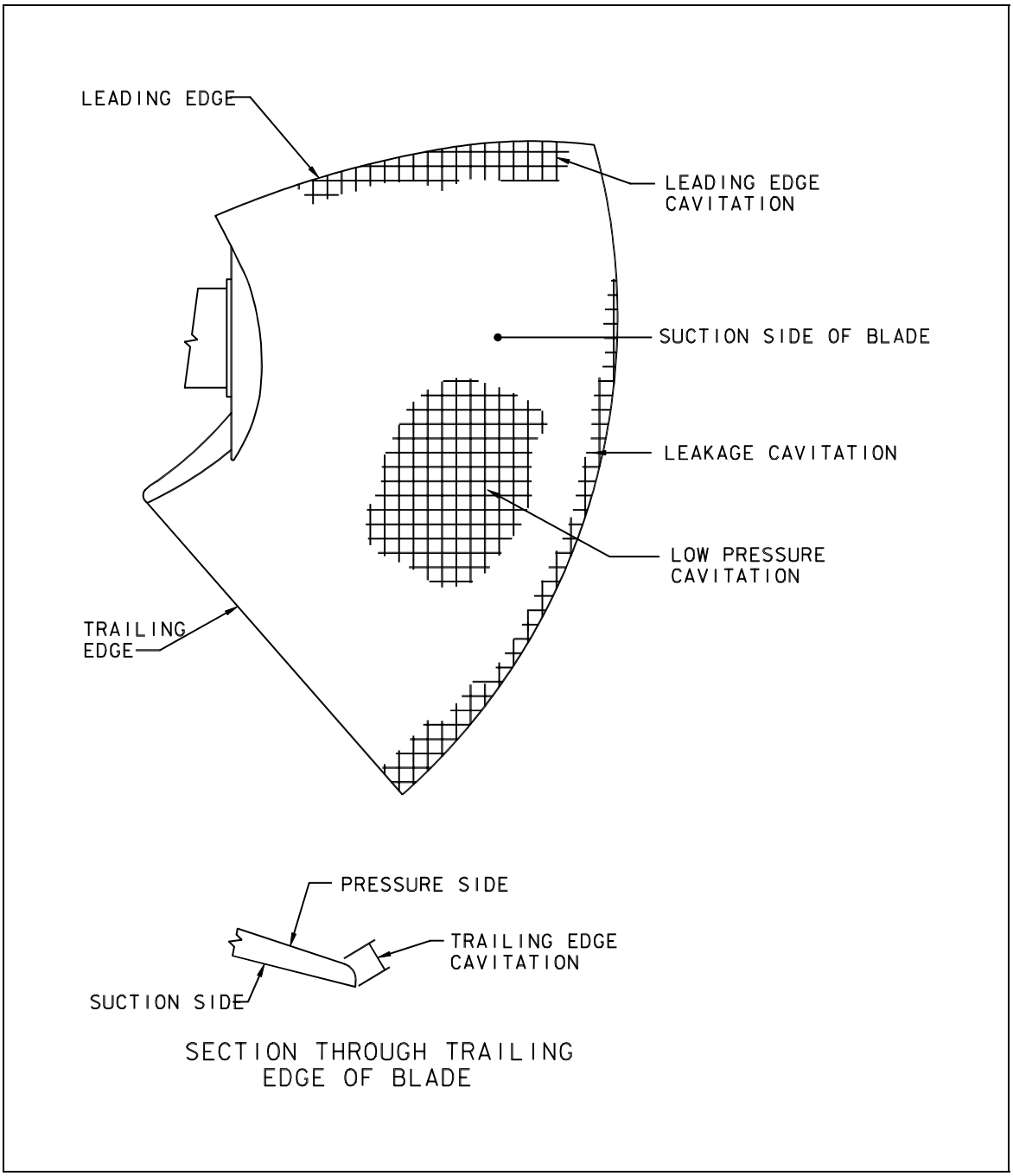

Figure 4-3
Areas of Runner Cavitation Pitting - Propeller and Kaplan Turbines
Reproduced from Cavitation Pitting Mitigation in Hydraulic Turbines, prepared by Acres International Corporation, EPRI Report No. AP-4719, August 1986, Volume 1, p. 4-10.

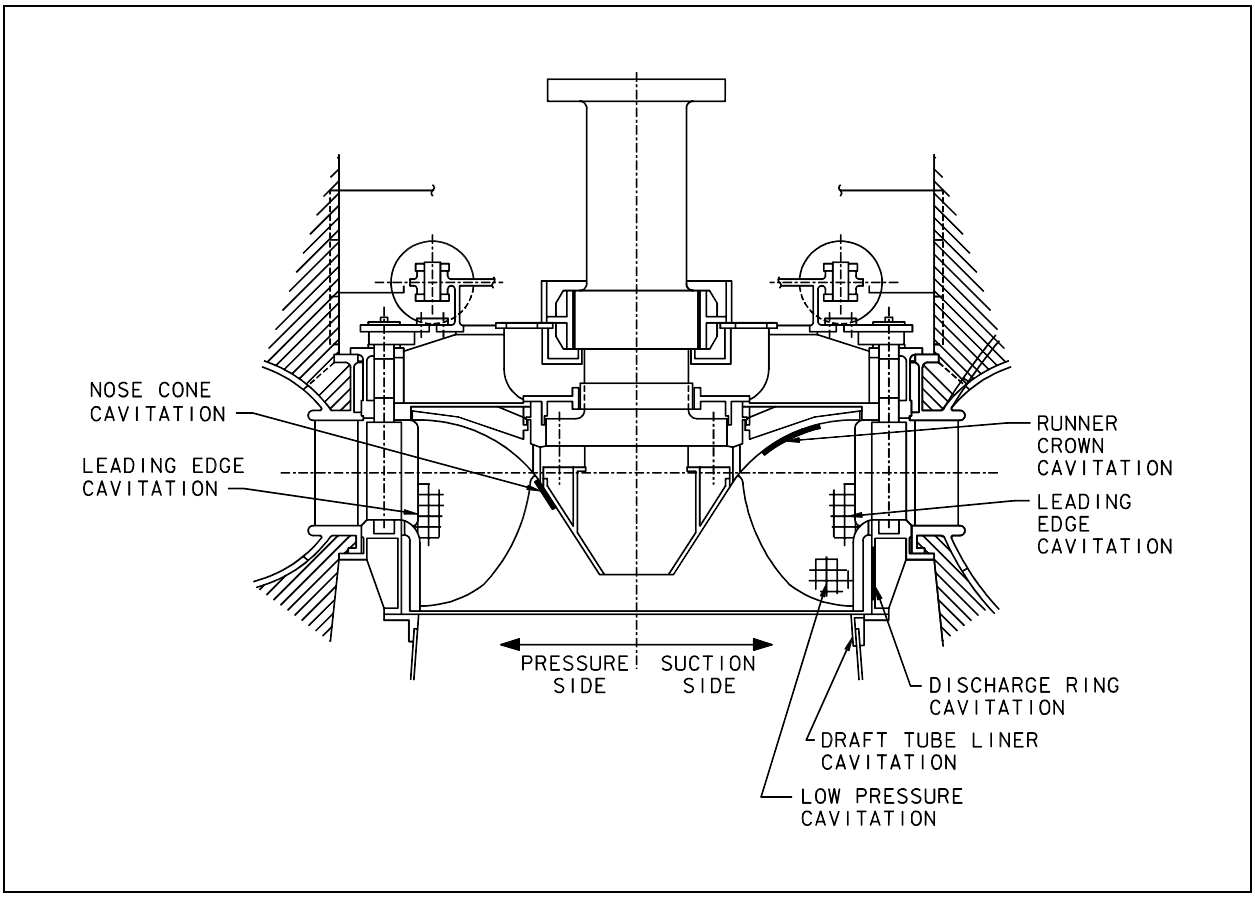

Figure 4-4
Francis Turbine - Typical Areas of Cavitation Pitting
Reproduced from Cavitation Pitting Mitigation in Hydraulic Turbines, prepared by Acres International Corporation, EPRI Report No. AP-4719, August 1986, Volume 1, p. 4-16.

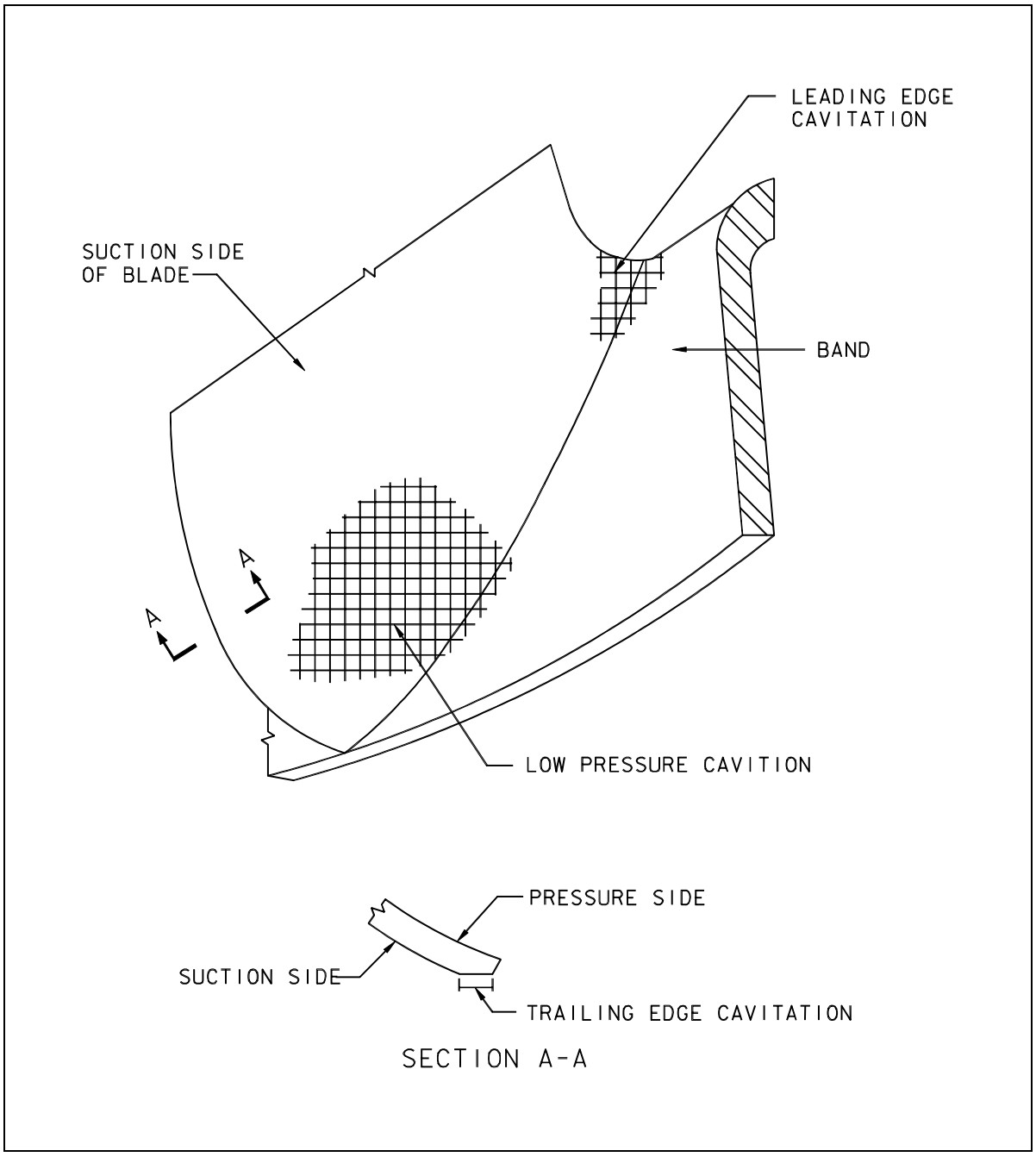

Figure 4-5
Areas of Runner Cavitation Pitting - Francis Turbine
Reproduced from Cavitation Pitting Mitigation in Hydraulic Turbines, prepared by Acres International Corporation, EPRI Report No. AP-4719, August 1986, Volume 1 p. 4-17.

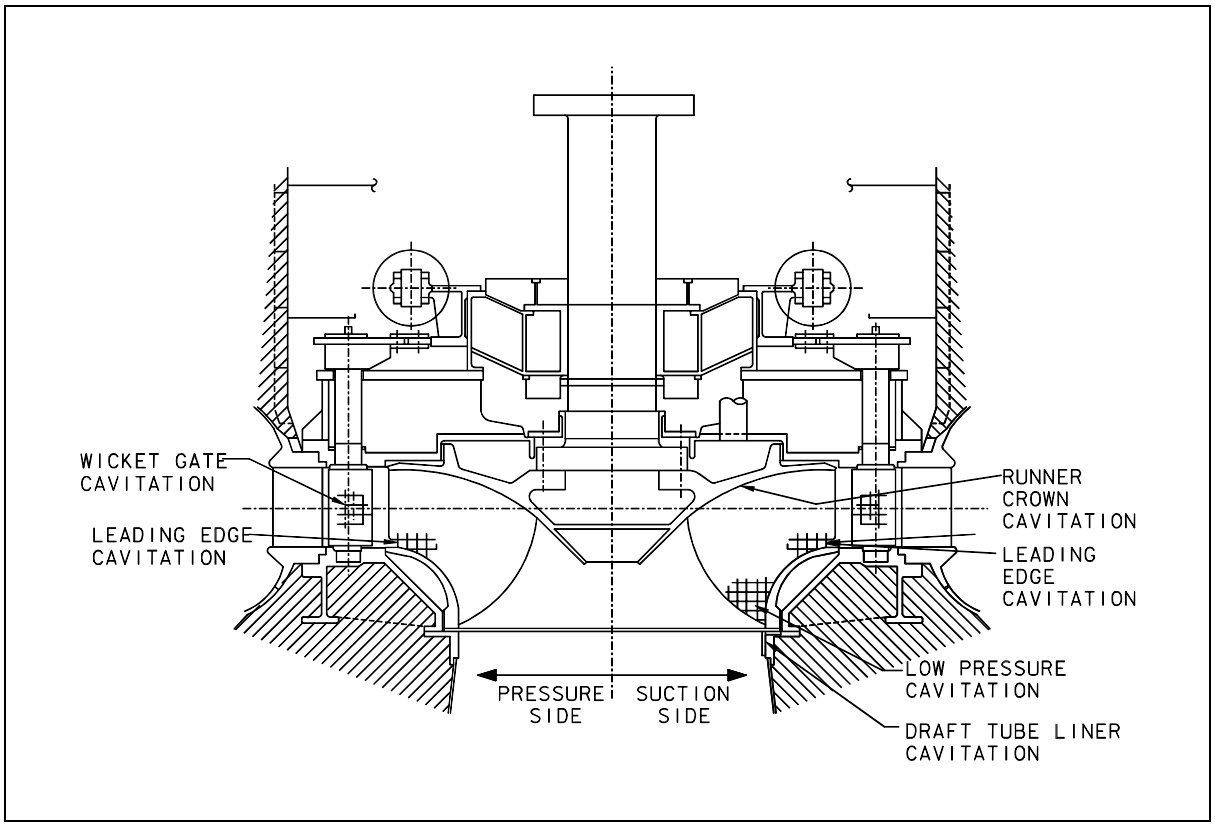

Figure 4-6
Pump-Turbine - Typical Areas of Cavitation Pitting
Reproduced from Cavitation Pitting Mitigation in Hydraulic Turbines, prepared by Acres International Corporation, EPRI Report No. AP-4719, August 1986, Volume 1 p. 4-24.

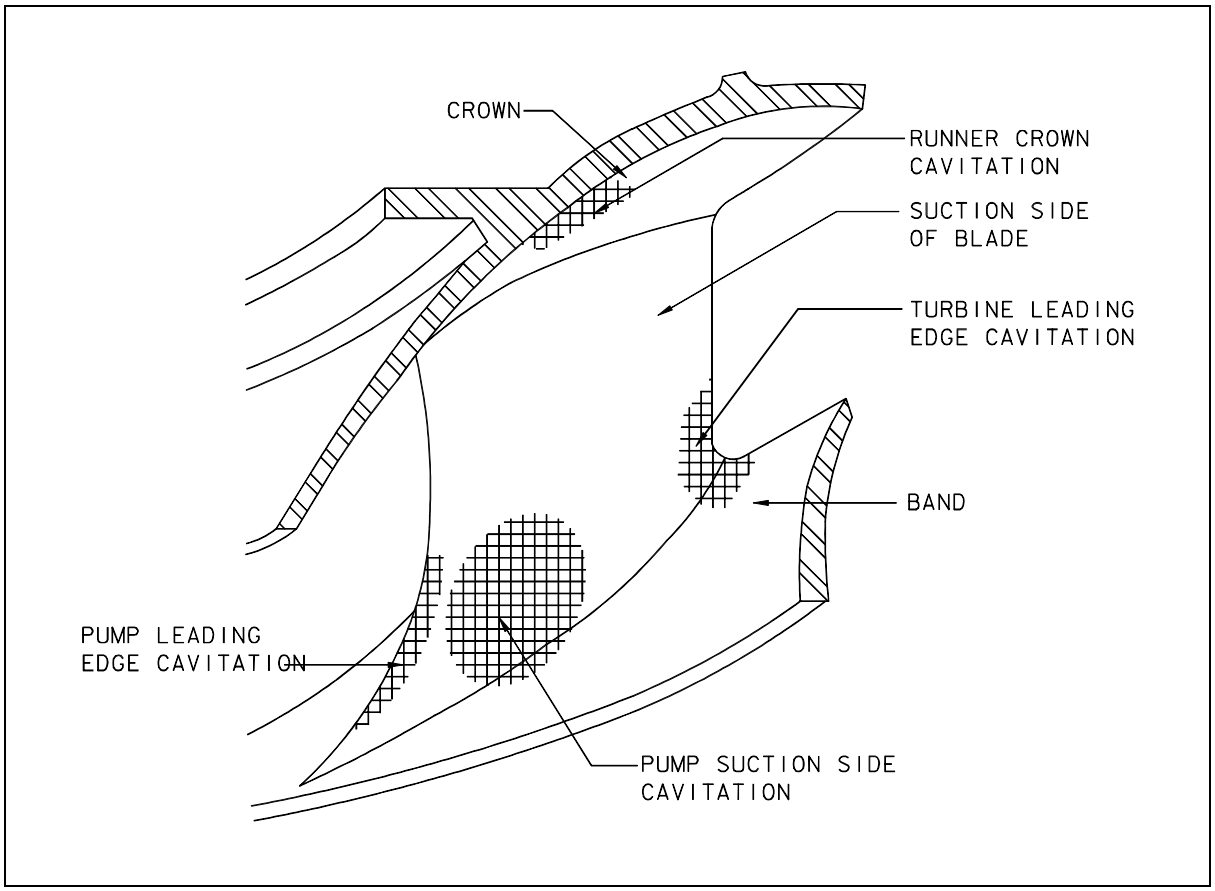

Figure 4-7
Areas of Runner Cavitation Pitting Pump-Turbine
Reproduced from Cavitation Pitting Mitigation in Hydraulic Turbines, prepared by Acres International Corporation, EPRI Report No. AP-4719, August 1986, Volume 1 p. 4-25.

It is recommended that a checklist be prepared to ensure that all parts of the turbine are inspected, and that all areas of cavitation damage be recorded on sketches or in tabular form. The records should include the following.

- Date of inspection.
- Number of hours of operation and the generation (MWh) since the previous repairs and/or inspection.
- Operating limits (i.e. net head, tail-water level, flows) and any incidence and duration beyond these limits.
- Overall area of each area of pitting, as well as the average depth and maximum depth.
- Dimensions of damage areas measured from the leading and trailing edge of the blades.
- Photographs of the damaged areas and of subsequent repairs.

As an example, typical REMR forms for recording cavitation pitting damage are provided in Appendix D. When taking photographs, the blade runner, the date of the inspection, and dimensions of the pitted area should be clearly marked on the blade for reference.

International Electrotechnical Commission (IEC) Publication, Code No. 609 gives four methods of measuring the amount of material loss on a turbine due to cavitation. These are:

- By direct measurement of the volume of a plastic filler
- By approximate calculation of area and depth of areas of metal removal
- On the basis of the amount of electrode material required for cavitation damage repair
- On the basis of the amount of working hours required for the repairs

In analyzing cavitation damage, the first check will be for local discontinuities in blade shape or profile in the area immediately upstream of the damaged surface. Another check will be whether or not the cvaitation patterns are the same on each of the blades.

If damage varies from blade to blade and there are no apparent discontinuities upstream, the problem may be on the overall blade profile or blade location.[10]

On new runners that have been designed using Computational Fluid Dynamics (CFD) and numerical design methods and fabricated using Numerical Control (NC) machining, there will rarely be any difference in the pattern of cavitation on different runner blades due to improved runner homology.

If the pattern of damage is very similar from blade to blade, and local profile discontinuities are not evident, identification of the problem becomes more difficult and other factors such as method of operation, operating heads, etc., must be considered. [10]

[10] U.S. Bureau of Reclamationm *Turbine Repair, Facilities Instruction, Standards & Techniques, Volume 2-5.*

Inspection of Pelton Runners[11]

Three locations of the bucket may be subject to pitting:

1. at the back of the bucket;

2. at the back of the bucket's leading edges, especially when the runner is operating in a multi-jet unit at high head. This kind of pitting is influenced by the specific speed of the wheel;

3. the surface inside the buckets, produced either by improper profile or disturbances of the jet(s).

Although the cause of pitting may be difficult to determine, flow disturbances can originate from:

1. the penstock and distributing pipe;

2. wear at the nozzle tip and nozzle ring;

3. wear and other damage such as impact-craters and flaws.

Frequency of Cavitation Damage Inspections

The frequency of inspections should be dictated by the extent of damage which is occurring. Frequent inspections are particularly important during the initial period of operation of a new turbine or new runner under warranty, as they will enable cavitation damage to be detected at any early stage and remedial measures to be implemented before pitting becomes extensive.

When a new turbine is placed into operation, the unit should be inspected after about 1500, 4000 and 8000 hours of operation. For pump-turbines, this frequency should be 750, 1500 and 3000 hours because of the potential for more severe cavitation pitting during pump operation. The manufacturer's recommendations or contractual requirements concerning inspection periods should be followed, particularly during the warranty period.

For older units which are experiencing minimal damage, the period between inspections can be increased.

The frequency of inspection should not be less than:

- Turbines every 24,000 operating hours or 2 - 3 years
- Pump-turbines every 12,000 operating hours or 2 years

[11] H. Grien, R. Angehrn, M. Lorenze; Sulzer Escher Syss Zurich. A. Bezinge; Grande Dixence, S.A., *Inspection Periods of Pelton Runners.*

Operating and maintenance experience, other than cavitation damage, may dictate a more frequent inspection (e.g., blade cracking, seal wear). Also, more frequent inspection is warranted when making runner profile modifications, to adequately monitor the effectiveness of the changes.

Erosion and Corrosion Damage Inspection

The possibility that damage is not the result of cavitation should be investigated:

- Damage may be from corrosion, particularly if the water has high oxygen content or high dissolved solids.
- On carbon steel runners with stainless steel overlay, damage at the interface of carbon steel and stainless steel is likely to be partially due to galvanic action. Large voids beneath overlay are caused by galvanic corrosion which occurs when there is a small hole in the overlay. The hole may be a defect in the weld overlay or the result of cavitation pitting which has penetrated the overlay.
- If the water contains large amounts of entrained solids such as silt, the damage may be caused by physical erosion rather than cavitation pitting. Damage will be on turbine components in areas of high velocity such as the headcover, bottom ring, wicket gates, stay vanes, and runners. Erosion due to silt occurs at all operating conditions, while cavitation will appear predominately on the suction (low pressure) side of the runner blades and can be avoided or minimized by restricting the operating range of the unit.

Pelton Runner Surfaces

For Pelton wheels, corrosion fatigue is the dominating process.[12]

The type of particulate, the flow velocity and the discharge are the parameters that affect the level of material erosion from the inside of the buckets. Very often erosion damage is caused by unsuitable and insufficient sand collectors. Normally erosion wear is distributed equally among buckets of a runner.

After some deterioration of the surface by erosion, cavitation pitting may start because of local vortices.[3]

An appropriate indicator of efficiency loss due to erosion on a Pelton runner is the width of the splitter as a percentage of bucket width. A one percent increase in splitter width represents approximately a one percent decrease in efficiency.

[12] H. Grien, R. Angehrn, M. Lorenze; Sulzer Escher Wyss Zurich, Switzerland. A. Bezine; Grande Dixence, S.A., *Inspection Periods of Pelton Runners.*

Cracking

Francis Runner Cracking

Runner cracking is a serious problem that requires immediate attention and should be investigated by a specialist. Runner cracks can propagate due to higher than acceptable design stresses, geometric stress concentrations, material and weld imperfections, or due to fatigue failure. A good philosophy to adopt is that all cracks should be repaired as soon as they are discovered. However, runner cracking is rarely the driver for runner replacement no matter how serious the problem is. Any crack that is greater than 1/2 inch (12.5 mm) long in an area of high stress on its blades (Figure 4-8) should be inspected every three to six months to evaluate the propagation rate. Any crack longer than 2 inches (50 mm) should be removed and repaired, provided the runner consists of a weldable alloy. The evaluation of critical crack length for nonweldable runners is beyond the scope of these Guidelines. If welding is used for crack repairs, the weldment should have a higher toughness than the parent metal.

Pelton Runner Cracking

The rate of runner wear (erosion) is usually higher on a multi-jet Pelton unit than a single jet one under the same water conditions. Likewise, the incidence of cracking or metal fatigue will be higher on a multi-jet runner as the runner sees a higher number of stress cycle alterations. Critical stress zones occur where the bucket attaches to the disc. This area needs to be free of casting defects or fatigue failure from the alternating stresses could occur.[1]

The crack locations can be classified roughly into three categories[15] :

1. cracks at the leading edge of the buckets which in most cases are self-arresting and do not significantly affect the structural integrity of the runner;

2. cracks at the bottom end of the bucket splitter near the critical stress zone at the root of the bucket for one piece cast runners. If these cracks reach the critical depth, catastrophic failure of the runner could ensue;

3. scattered cracks, which may occur at any location in the runner where the stressing by hydraulic and mechanical forces is small but residual stresses due to material defects or improper heat treatment are sometimes sufficiently high to initiate cracking.

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[1] American Society of Mechanical Engineers, Hydropower Technical Committee, HCI Publications Inc., Kansas City, MO 1996, *"The Guide to Hydropower Mechanical Design"*

[15] H. Grein, R. Angehrn, M. Lorenze; Sulzer Escher Wyss Zurich, Switzerland. A. Bezinge; Grande Dixence, S.A., *Inspection Periods of Pelton Runners.*

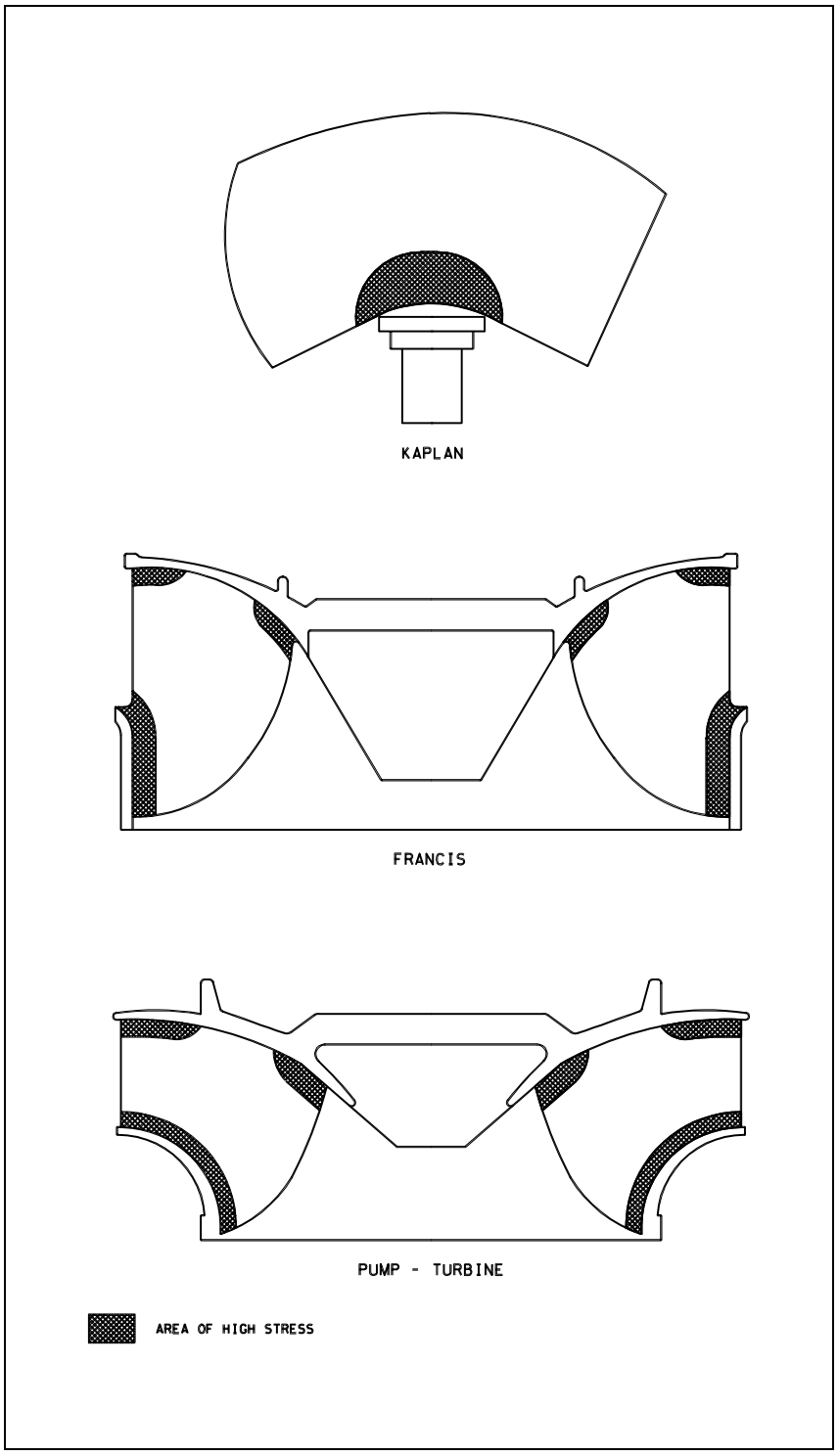

Figure 4-8
Areas of High Stress on Turbine Runners

Seal/Blade Clearance

Turbines with a radial seal clearance exceeding 0.250 inch (6.35 mm) are good candidates for life extension by replacing the wearing rings or weld overlay and machining to reduce the clearance to the original value. The potential for increasing efficiency by reducing the clearance can be estimated using Figure 4-9.

Hydraulic turbine efficiency decreases as runner seal or blade tip clearances increase. Runner seal or tip clearances are a measure of the area available for water to bypass the turbine runner and reduce efficiency. Therefore, measurement of the runner seal or blade clearances and surface roughness can also be used to estimate the reduction in turbine efficiency. The average of at least four runner measurements around the runner periphery can provide a reasonable estimate of the runnel seal or tip clearance. Runner clearance measurements can be made with a precision rule or tapered device to measure the space between the rotating runner wearing ring or blade tip and the stationery wearing rings or discharge ring. An average of the runner clearance measurements accurately determines the runner clearance. For new turbines, the radial clearance is approximately 0.02 - 0.04% of diameter for a Francis turbine (the crown has a tighter tolerance than the band because it is closer to the bearing; seal clearance is a function of the bearing clearance) and 0.06% of diameter for a Kaplan turbine. The runner design clearance is typically shown on the turbine assembly drawing.

Increased runner seal clearance or blade tip clearance should be recorded. Based on these measurements, the turbine efficiency reduction due to seal or blade tip clearances can be estimated from Figure 4-9.

Surface Condition

Hydraulic turbine efficiency decreases as runner blades and other water passage surfaces finishes deteriorate. In particular, the surface finish of the stay ring shrouds, stay vanes and wicket gates should be carefully evaluated. Runner surface roughness can be estimated by using surface finish comparators. The reduction in efficiency due to surface finish deterioration over the entire unit can be estimated to be between 1 to 2% for a surface finish between 500 and 1,000 microinches (12.5 μm/25 μm).

Kaplan Blade Mechanism

The blade movement should be inspected by running the runner servomotor to fully open and closed positions. During this operation, the runner should be checked for oil leaks between the blade flange and runner hub. Checks should also be done to ensure that the gland ring bolts around the blade flanges are intact. Smoothness of blade movement under load should also be observed. A jerkiness or slip-stick movement could indicate a problem with the bearings or the bearing lubrication.

See Section 4.4.7 for a discussion on how to assess whether or not there is sufficient reserve capacity in the hydraulic pressure supply system (governor system) to effectively operate the runner blades.

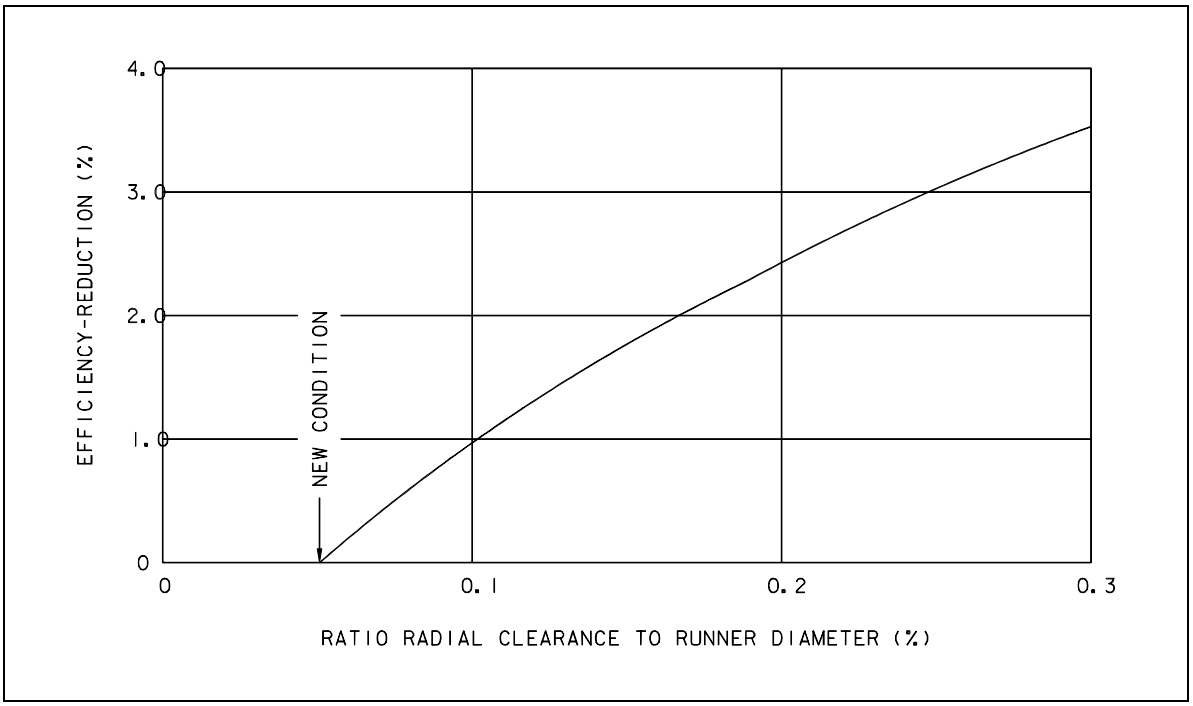

Figure 4-9
Reduction of Efficiency due to Runner Gap Clearance of Francis, Propeller and Kaplan Turbines at Full Load

4.4.3 Wicket Gates and Wicket Gate Operating Mechanism

Wicket Gates

Surface corrosion and leakage are the indicators to evaluate the turbine wicket gates. Although surface roughness has a significant affect on turbine efficiency, repair of surface corrosion is normally not required until the pitting depth exceeds 3/16 inch (4 mm). Wicket gate leakage between the head cover and bottom ring clearances and between adjacent closed wicket gates contributes to lost generation during unit downtime or synchronous condense operation. Wicket gate leakage can be estimated by measuring the gate clearances and calculating the leakage using the following formula:

$$\text{Leakage} = K_i \pi D (s_1 + s_2) C \sqrt{2gH} \quad [4\text{-}1]$$

where:

Leakage	=	ft^3/s (m^3/s),
K_i	=	resistance coefficient of 0.4,
s_1	=	average measured wicket gate top clearance, in (mm)
s_2	=	average measured wicket gate bottom clearance, in (mm)
D	=	pitch circle diameter of wicket gates, ft (m),
H	=	operating head, ft (m), and
g	=	acceleration due to gravity, 32.2 ft/s^2 (9.81 m/s^2)
C	=	adjustment for inconsistency in units
	=	0.083 for in or ft units
	=	0.001 for mm or m units

The formula for intergate leakage is:

$$\text{Leakage} = K_2 \, j \, i \, n_g \, C \sqrt{2gH} \quad [4\text{-}2]$$

where:

K_2	=	resistance coefficient = 0.5
D	=	wicket gate pin circle diameter, ft (m)
i	=	wicket gate height, in (mm)
n_g	=	number of wicket gates
j	=	average measured clearance between wicket gate nose and tail with the wicket gates closed, in (mm)
g	=	acceleration of gravity, 32.2 ft/s^2 (9.81 m/s^2)
H	=	operating head, ft (m)

Total leakage for new wicket gates (top, bottom and intergate) can be estimated as less than 0.5% of turbine maximum discharge, and if the existing total leakage exceeds 2% of maximum discharge or four times the new condition leakage rate, repair should be considered if the unit is shut down with the intake gate open more than 20% of the time. Another indication of the need to reduce wicket gate leakage is if the turbine cannot easily be stopped even with the use of the braking system, or if the turbine starts to creep if the unit has been stopped and the brakes are released.

Increases in wicket gate leakage over the years can be detected by monitoring the time required for the unit to stop, if all governor shutdown settings remain the same.

Wicket Gate Bearings

Wicket gate bearings position the wicket gates for precise control of flow to the turbine. Eventually, wear of the wicket gates and bearings increase the bearing clearance, which results in misalignment of the gates, increased leakage, increased friction and increased servomotor force required to operate the gates. This condition can contribute to increased shear pin or breaking link failures and overstressing of the servomotor and governing systems. The condition of the wicket gate bearings can be assessed by measuring the wicket gate clearances and gate mechanism bearing clearances using feeler gauges. Alternatively, the gates can be jacked from side to side and the gate clearance can be measured with dial indicators. The diametrical clearance of new wicket gate bearings is approximately 0.010 to 0.020 inch (0.25 to 0.50 mm), and measurements of 0.060 inch (1.5 mm), or greater than three times the design value, indicate the need to rebush the bearings and refinish the gate shafts.

Operating Ring, Wicket Gate Links, Levers and Servomotor Connecting Rods

The condition of the wear surfaces of these components should be inspected and recorded. It may be possible to remove a gate link or connecting rod and evaluate the wear on the link pins and bushings. A bushing clearance of 2 - 3 times design clearance is an indicator of wear. The history of the shear pin failure should be reviewed. The wear of the operating ring wear strips should be inspected and recorded if at all possible.

Servomotor

The turbine servomotor converts hydraulic pressure to mechanical force to position the wicket gates in response to governor commands. Wear of the movable servomotor piston rings and scratches on the cylinder walls cause higher oil leakage past the servomotor piston as the servomotors age. Any leaks from the high pressure side to the low pressure side increases the cycling frequency of the governor hydraulic pumps but frequent cycling does not necessarily mean that the servomotor is worn. Servomotor leakage can only be reliably measured by pressurizing one side and measuring the leakage from the other side of the piston or cylinder. Leakage of the governor's distributor valves and unit hunting are also factors in pump usage. Installation of a continuously running jockey pump can reduce wear on main governor pumps.

Very severe servomotor leakage can also be detected by opening and closing the gates at the maximum rate to determine if the servomotors stall during operation.

Measurement of the servomotor high side pressure with the wicket gates in the fully open or closed position is another method to investigate excessive servomotor leakage. If the servomotor pressure is more than 5% below the governor pressure, it is likely that the servomotor leakage is excessive and needs to be corrected. Pressure measurements should be made by properly calibrated gauges for the comparison to be valid.

4.4.4 Nozzle Assemblies and Deflectors (Peltons)

The surface finish of a needle, nozzle or needle seat ring often deteriorates due to erosion from sediment in the water. A deteriorated surface can disturb the jet leaving the nozzle assembly and adversely affect turbine efficiency. In an extreme condition, a deteriorated needle tip or seat ring will not allow the unit to fully shut down without application of brakes or closing of the turbine inlet valve. A severely eroded needle tip and nozzle seat ring can reduce turbine efficiency up to 5%.

Sediment in the water can also cause erosion of the deflectors, particularly if the deflectors are frequently in the flow regime. Frequent operation of the deflectors is possible if the turbine is on speed control. The deflectors should be repaired or replaced if, because of wear, deflector operation no longer adequately diverts the flow from the runner, governor speed control is no longer effective, or if the structural integrity of the deflector is in question (typically a 25% reduction in thickness).

See Section 4.4.7 for details on the assessment of nozzle assembly and deflector servomotors which is similar to the assessment of wicket gate servomotors.

IEC Standard No. 60193 provides guidelines on the surface roughness of wetted parts, including tolerances for Pelton nozzle assemblies.

4.4.5 Other Turbine Components

Spiral Case, Baffle Plates, and Distributor (Pelton)

The turbine spiral case serves to direct flow to the distributor and runner. If the spiral case walls are severely corroded, the efficiency and maximum output of the turbine can be affected. This can be evaluated by calculating the friction loss assuming the spiral case is a circular pipe.

The surface condition of the spiral case or distributor should be recorded. Refer to Table 4-10 for examples of changes in turbine efficiency over time due in part to deterioration of surface conditions.

Corrosion of the spiral case walls can also reduce the wall thickness to such an extent that the structural integrity of the spiral case is affected. Ultrasonic thickness measurements should be made on the spiral case to determine the wall thickness. By comparing these thickness measurements with original design values or with previous thickness measurements, the rate of thickness change can be estimated along with the theoretical remaining life of the spiral case.

The rate of spiral case thickness deterioration can be reduced by application of a high quality protective coating.

Some Francis turbines have a steel baffle at the small end of the spiral case to provide suitable hydraulic contour for flow entering the distributor. While a baffle is not a structural component, it is typically welded to the spiral case. Cracks can occur in the baffle, usually at the welds, due to stress from spiral case expansion and/or resonance from various forcing frequencies. This baffle should be inspected by NDT methods to ensure that cracking is not occurring. If cracks are forming in the baffle due to resonance, the problem may be mitigated by altering the natural frequency of the baffle plate.

IEC Standard No. 60193 provides guidelines on the surface roughness of wetted parts, including tolerances for Pelton nozzle assemblies.

Stay Vanes, Stay Ring and Discharge Rings

These components should be inspected for erosion damage if the runner has shown similar damage.

The stay vanes are an important structural component of the turbine. They serve to transmit the casing pressure forces between the upper and lower halves of the spiral case. In this regard the fillet areas at the top and bottom of the stay vanes are often the most highly stressed areas. As part of a condition assessment of the turbine, NDT of the stay vane fillets should be made. Any cracks should be carefully repaired. If any modifications to the stay vanes are contemplated (as part of turbine upgrade) the effect of the modification on stay vane stresses should be examined.

Stationary (Wear) Rings and Seal Rings

There have been problems in the past with the seal and wear rings that were installed on Francis runners with a shrink process to fit them to the runner. The shrink installation may lose its clamping tension or fasteners.[16] A loose wear ring could result in a more serious problem and should be addressed carefully.

4.4.6 Shaft, Shaft Seal and Guide Bearings

Shaft and Shaft Seal

The turbine shaft transmits mechanical torque from the runner to the generator shaft or rotor. The shaft surfaces to be inspected are the shaft seal wear surface and bearing journal. Assessment of the shaft seal wearing area is made in conjunction with the shaft seal. Excessive leakage past the shaft seal can overload the pit drainage system, which can be tested by supplementing the leakage water with an additional 10 gpm (37.85P/m) from an auxiliary hose.

[16] American Society of Mechanical Engineers, Hydropower Technical Committee, HCI Publications Inc., Kansas City, MO, 1996, *"The Guide to Hydropower Mechanical Design"*

If the additional water does not overload the drainage system, the shaft seal leakage can be considered to be acceptable.

A second criterion for assessing the condition of the shaft seal and bearing areas is the surface finish. A new unit would have a surface finish of 32 rms (0.8 μm) for the bearing journals and shaft seal wear areas, and deterioration of these surfaces would necessitate refurbishing the respective surfaces. Guide bearing losses would increase for rougher journal bearing surfaces and can be evaluated by the bearing operating temperature. Bearing operating temperature under full load should be recorded. Typical oil-lubricated turbine guide bearings operate below 140°F (60°C). High temperature operation, coupled with the determination that the journal surface finish has deteriorated, may signal the need to consider correction. A bearing temperature is dependent on other factors such as vibration, clearance, alignment, and oil quality, any evaluation should also consider these potential problems. A review of the operating records of the turbine bearing temperature can also be used to indicate any increasing trend in bearing temperature and need for correction.

Shaft water seal wear can be excessive if the shaft seal wear surface finish has deteriorated and "rings" are appearing. Therefore, adjusting the shaft seal more than every six months or replacing the shaft sealing elements more than every five years may indicate that the deteriorated shaft seal area should be corrected.

Assessment of the shaft condition should also include a complete inspection of the shaft for cracks. Cracks in the shaft of vertical units are extremely rare and would only occur under cases of severe shaft misalignment. A change in vibration levels would indicate this. On horizontal units, the shafts are subject to bending fatigue and may be more susceptible to cracking. The most likely locations for cracks to develop are in areas of high stress concentrations, such as the area of the bearing journal upset. The shaft inspection of the turbine journal area requires disassembly of the turbine bearing. If the minimum turbine shaft diameter is unavailable from the existing drawings, this measurement should be made and recorded along with the shaft material.

Guide Bearing

Turbine oil-lubricated guide bearings are typically provided with a low friction babbitt material bonded to the bearing shell or pads. Assessment of bearing condition should include inspecting the babbitt material for cracks by using the dye penetrant method and bonding of the babbitt to the shell/pads by ultrasonic inspection methods. If a visual inspection of the babbitt material reveals discolorations indicating hot spots, the bearing condition may be due to shaft journal finish deterioration or improper oil quality. The shaft journal finish assessment is described in previous paragraphs and oil quality tests can be made by local laboratories. Oil quality tests should be carried out on a regular basis in order to establish a "base" quality. The bearing lubrication system is covered in Volume 4 "Mechanical Auxiliary Equipment". If cracks or lack of bonding to the shell/pads are found on the bearings, rebabbitting or machining should be considered.

Guide bearing clearance and runout measurements are also good indicators of bearing and turbine condition. For comparison, the radial clearance for new turbine guide bearings is 0.0003 inch/inch (0.008 mm/mm) of shaft diameter but clearances are typically 0.009 to 0.01 inch (0.23 to 0.25 mm). Runout at rated load is also typically less than 0.004 inch (0.10 mm) for a 30 inch (762 mm) diameter shaft. If the radial bearing clearance exceeds:

- 0.010 inch (0.25 mm), or
- twice the design value,

guide bearing rehabilitation should be considered.

If runout exceeds 75% of the bearing radial clearance, alignment or balance problems are probably indicated, not a problem with the bearing itself.

For more information on bearing clearance and runout criteria, refer to CEA's "Guide for Erection Tolerances and Shaft Alignment". German Standard VD1 2059 also provides guidelines on shaft runout criteria.

Excessive turbine shaft runout and vibration also indicate the extent of mechanical and/or hydraulic imbalance and/or misalignment of the turbine. Therefore, excessive guide bearing temperatures and runout may indicate the need to investigate the cause of the vibration. A monogram of allowable vibration levels in hydro units is shown is Figure 4-10.

The allowable vibration levels shown in Figure 4-10 were developed by the Russian organization, ORGRES, which was the first to develop vibration standards for hydroelectric turbine generators. Other standards include German Standard VDI 2056 which is slightly less conservative. A brief summary of the information contained in the nomogram follows.

The left half of the nomogram has curves of peak-to-peak vibration amplitude versus runner diameter. The vibration amplitude is the maximum amplitude regardless of the direction. The right hand side of the nomogram indicates regions of Poor, Satisfactory, Good, or Excellent vibration levels as a function of shaft speed. The allowable vibration displacements for hydraulic turbines are a function of the runner diameter and synchronous speed.

The allowable vibration displacements determined from Figure 4-10 are peak-to-peak amplitudes at synchronous frequency when the vibration is predominately synchronous. If the displacement frequencies are random, the root mean square of the amplitudes is used instead of peak-to-peak amplitude. The unit vibration is the greatest vibration amplitude that occurs at synchronous speed between no-load and full-load.

The example in Figure 4-10 is a unit with a 16 foot (5 m) diameter runner operating at 257 rpm. The vibration of the unit would be considered as follows:

Vibration Amplitude	Condition
0.0012 to 0.003 (0.031 to 0.076 mm)	Good
0.003 to 0.005 (0.076 to 0.127 mm)	Satisfactory
Above 0.005 (0.127 mm)	Poor

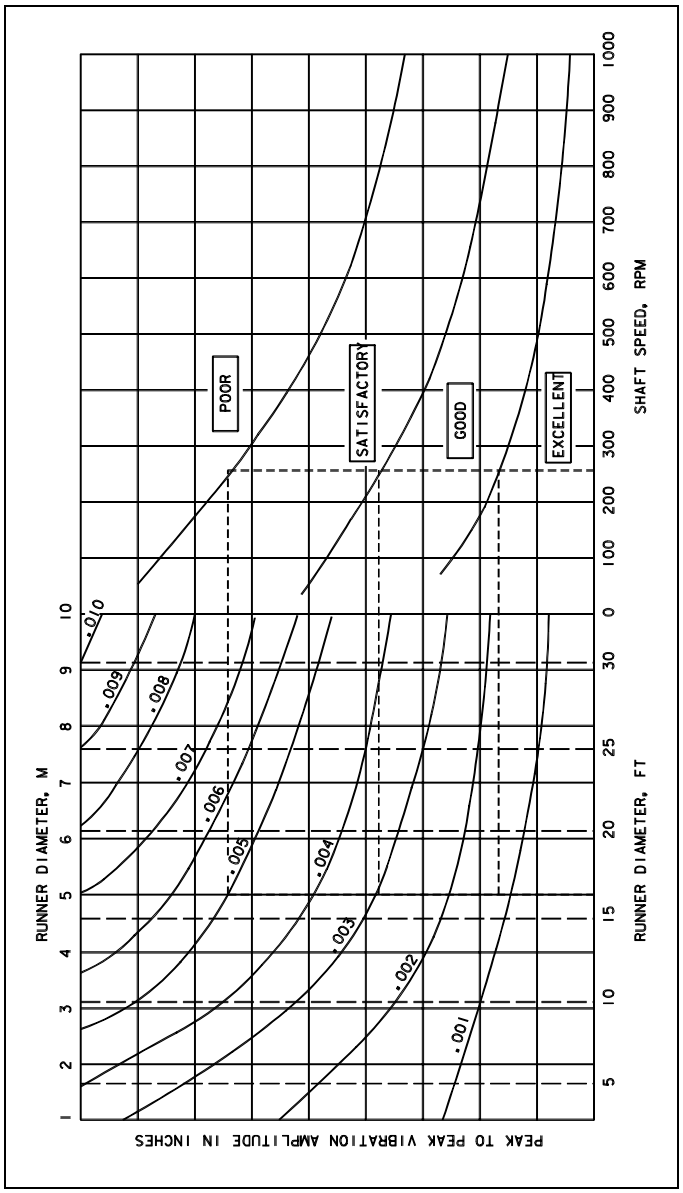

Figure 4-10
Nomogram for Determining Allowable Vibrations of Hydro Units
Source: Redrawn from "Vibration Analysis for Life Extension of Hydroelectric Turbine Generators, " Marcus Crahan, III and Duane A. Gettman. Presented at the Annual Meeting of the Hydroelectric Operation and Maintenance Conference: Plant Life Extension, February 18-20, 1986, the Electric Power Research Institute.

Typically, bearing vibration is measured on the bearing housing for high speed horizontal shaft machines. However, hydro units have low speeds and displacement of the housing does not give a good indication of actual shaft vibration. The common practice today, particularly on vertical units with journal bearings, is to use non-contacting displacement transducers (eddy current probes) mounted in or on the bearing housing and looking at the shaft (preferably the bearing journal). These probes will measure the combination of shaft runout (shaft machining and alignment anomalies) and relative shaft vibration, due to unbalance, hydraulic forces, etc.

The Canadian Electrical Association (CEA) publication "Hydroelectric Turbine-Generator Units - Guide for Electric Tolerances and Shaft System Alignment" recommends that shaft runout at the guide bearings not exceed 0.7 times the radial design clearance of the guide bearing. Another reference is from VDI 2059, as presented on Figure 5-19, in Section 5.8.2.

Vibrations are affected by the temperature of the journals and oil pot components due to thermal expansion and therefore vibration measurements should be taken at normal operating temperatures.

4.4.7 Governing Equipment

Governors and controls are often included in hydro plant life extension or modernization projects. Properly operating governors and controls are not only important for plant efficiency and reliability but also for plant safety.

The governing equipment for hydraulic turbines performs three basic functions:

- speed/load regulation,
- turbine shutdown,
- turbine startup.

The governing equipment is required to provide smooth and controlled startup, loading, unloading, and shutdown of the unit under normal operation.

Speed regulation involves maintaining a constant unit speed or load and, thus, a nominally constant generator frequency. This is accomplished by adjusting the turbine wicket gate or needle valve opening to control flow through the turbine in response to speed and load changes on the generator.

The governing equipment is also required to shut down the turbine within the design limits of penstock pressure rise and unit overspeed during load rejection from the electric system.

The governing equipment consists of three basic subassemblies. These subassemblies include:

- speed sensing and response circuits (governor head),
- hydraulic amplifier,
- hydraulic oil pressure system.

The speed sensing and response circuits provide measurement, processing, and regulation of control signals for control of the turbine generator unit.

The hydraulic amplifier converts and amplifies the speed signals from the speed sensing and response circuits into hydraulic forces to control the turbine servomotors.

The hydraulic oil pressure system provides the pressure to control the wicket gate, needle, and runner blade servomotors (if applicable). This system normally includes an oil/air pressure tank, an oil sump, a pump system, and associated controls.

The governing system condition is assessed to determine its ability to maintain proper speed regulation, regulating capacity and physical condition.

Speed regulation is discussed in Section 4.5 "Performance and Operational Information".

Some of the major components of the governor system that should be inspected include:

1. Governor Head
   - mechanical restoring linkage
   - indication and electrical control circuitry
   - transducer
   - speed switches
   - speed sensing source
   - creep detector
   - other transducers, limit switches, gauges
   - speed and power reference setters
   - mechanical speed control (fly-balls, etc.) where applicable
2. Hydraulic Amplifier
   - distributing valve
   - auxiliary and pilot valves
   - shutdown solenoid
   - gate position and gate limit mechanisms
   - actuator lock mechanism
   - general mechanical condition (dirty, leaking oil, etc.)

3. High-Pressure Oil System
   - piping
   - accumulator tanks
   - level detection and pump control circuitry
   - pumps (including motors)
   - unloader valves
   - condition of oil and sump
   - filtration systems
   - make-up air system

Regulating Capacity

Regulating capacity is the governor force available to operate the wicket gates to control the flow of water to the turbine. The required force is determined from the hydraulic and mechanical characteristics of the turbine unit and water conveyance system. For current designs, the governing force is provided by an oil pressure system and hydraulic servomotors.

Formulas exist to estimate the required governor capacity as a function of turbine type, size (wicket gate pitch diameter), flow, and head. However, these formulas are based on friction factors for new or well maintained turbines and may not consider the condition of a deteriorated turbine after many years of operation. Therefore, the actual governor force should be measured to determined the existing capacity margin. This can be done by a simple "indicator" test. Previous test reports should be used at this stage of the condition review but the following briefing describes an indicator test:

1. Install pressure gauges on both sides of the servomotors or servomotor oil piping.

2. Load and unload the unit slowly from speed no-load to full load and back to closed wicket gate position.

3. Take simultaneous readings of the pressures and servomotor stroke at five to eight gate positions in each direction. Also record any pronounced pressure peaks and the corresponding gate position.

4. Plot the pressure readings versus servomotor stroke on a diagram similar to Figure 4-11.

The difference between the opening and closing servomotor pressure is proportional to the governor force required to move the wicket gates. The maximum pressure differential (measured at the fully closed and fully open position) indicates the maximum force available. Therefore, comparison of the maximum pressure during operation with the maximum pressure in the closed position will indicate the available margin in the governor regulating capacity.

This same procedure is applicable to the blade mechanism of Kaplan turbines or the needle valves of Pelton turbines. Figure 4-12 is a diagram from a recent Kaplan turbine runner blade test. The figure shows that there is ample reserve capacity over most of the servomotor stroke except that nearly maximum pressure is required to overcome the stalling forces at 22° blade angle. The test results in Figure 4-12 indicate that a mechanical problem exists in the turbine at this blade angle.

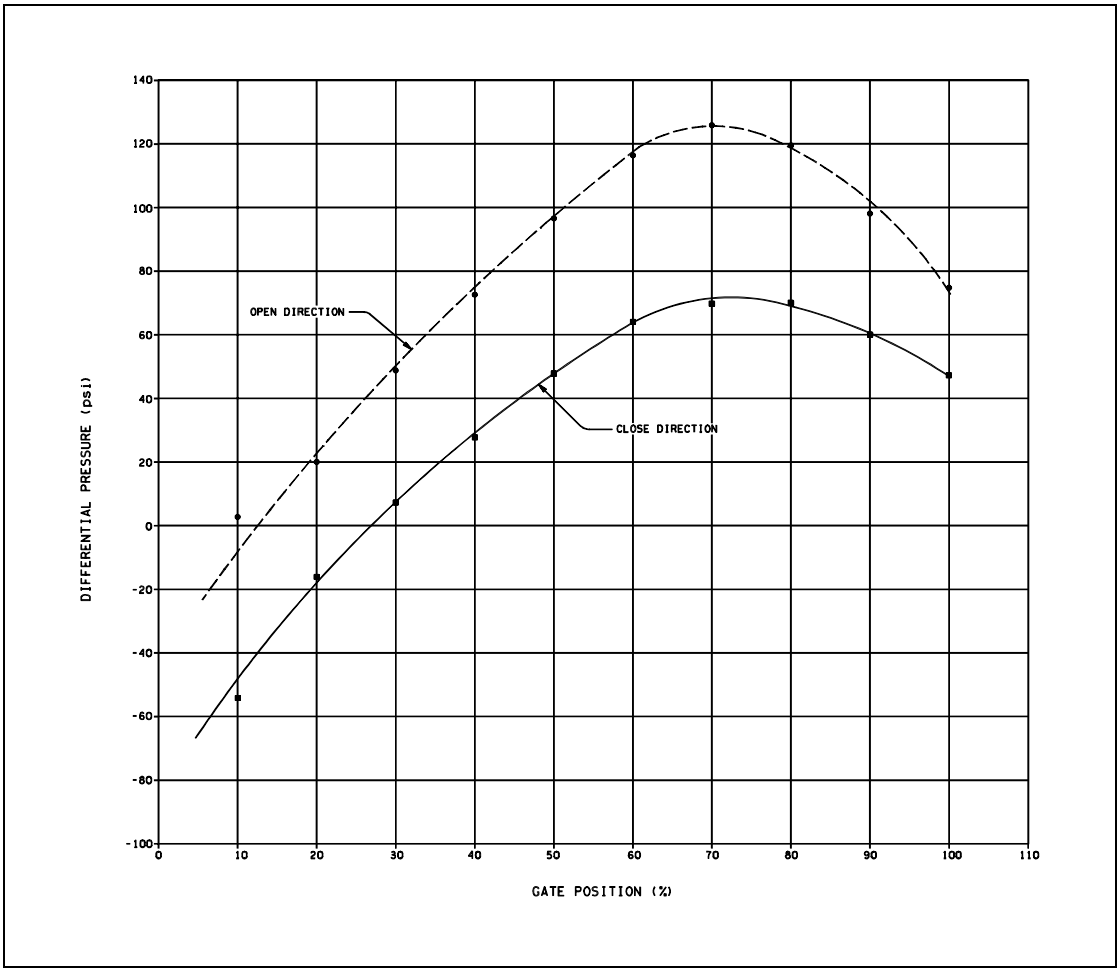

Figure 4-11
Example of Indicator Test Results for Wicket Gate Servomotors

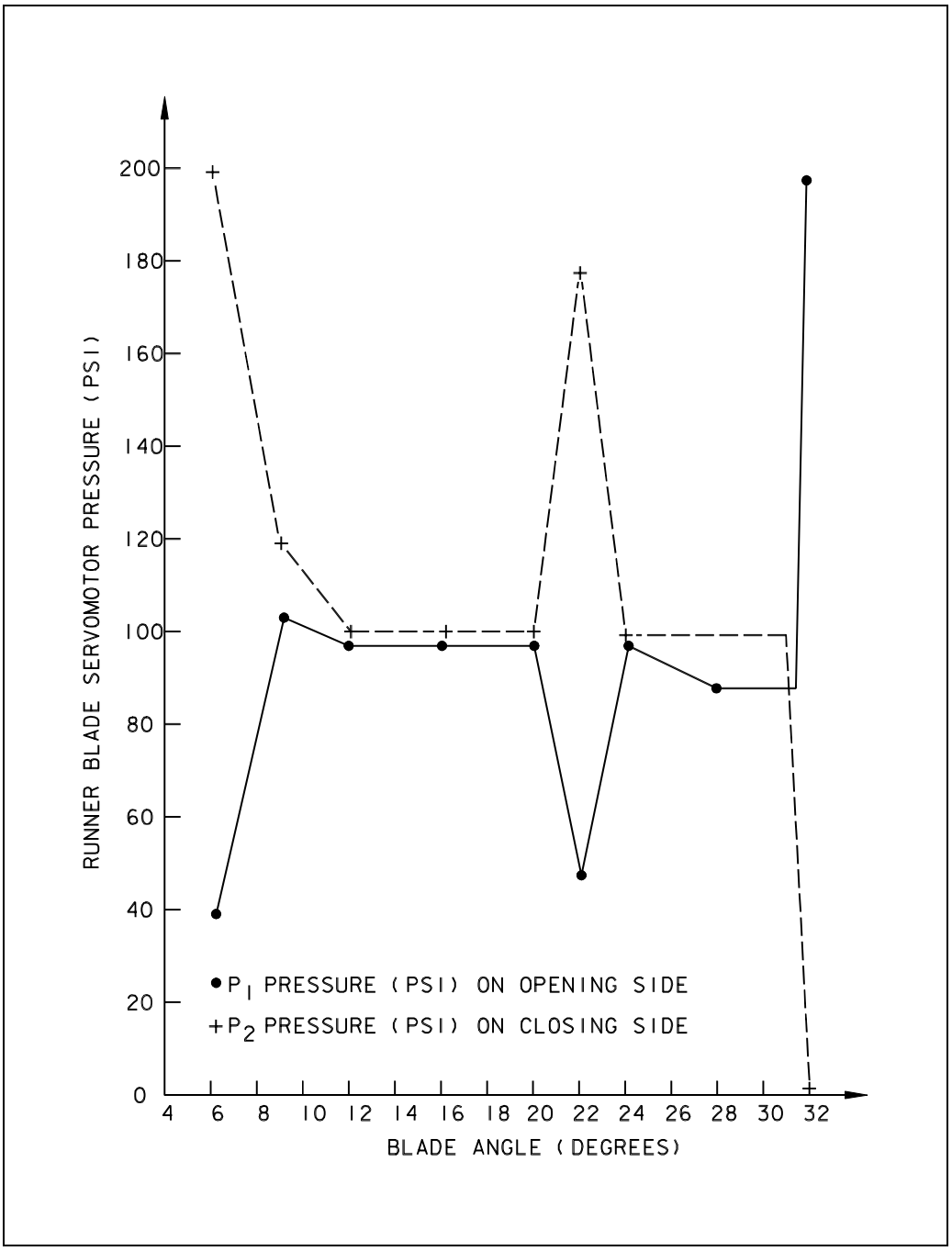

Figure 4-12
Servomotor Oil Pressure During Closing of the Blades with Closed Wicket Gates for Kaplan Turbine

As demonstrated in the example, an indicator test can be used to determine the amount of reserve governor capacity and also identify turbine control problems. After years of turbine operation, increased friction may restrict wicket gate movement because of the following factors:

- bearing wear of the wicket gate and operating mechanism,
- excessive gate to headcover friction or bottom ring contact,
- accumulated silt and debris,
- corrosion,
- bent wicket gate shafts,
- head cover and bottom ring misalignment.

The resultant servomotor force required to move the wicket gates may be greater than the force required for a new unit and may exceed the governor capacity. Although one alternative may be to increase the governor capacity (usually requiring an increase in hydraulic pressure), a more desirable solution would be turbine rehabilitation to reduce the friction to an acceptable level. As a result, the existing governor capacity would be sufficient and may also allow uprating the turbine discharge. If the test results demonstrate that the blocked servomotor pressure is less than the governor pressure, it is likely that excessive oil leakage occurs at the servomotor piston. As a result, rehabilitation of the servomotors will be required (see Section 4.8).

If the alternative of increasing governor capacity is chosen, then the design and ratings of all the components of the high pressure oil system would need to be checked.

Physical Condition

The physical condition of the governing system may deteriorate over the service life of the governor. Table 4-6 lists potential deficiencies in governing systems which may lead to operating problems and reduced reliability. This table also lists recommended remedies for these particular problems.

Table 4-6
Potential Operating Problems for Governing Systems

Deficiency	Possible Effect	Remedy
Unreliable Turbine Shutdown	• Turbine cannot be shut down and stopped in the event of a load rejection or normal shutdown scenarios	• Install emergency closing device, independent of governor. • Rehabilitate governor hydraulic system. • Replace governor system (partial). • Possible shear pin failure - check and replace.
Worn Control Valve	• Change in governor operating characteristics • Erratic governor response	• Rehabilitate governor control system.
Defective Speed Detector	• Frequency control unstable • Major load swings • Governor hunting	• Rehabilitate or replace affected components; for example, replace fly balls, Permanent Magnet Generator (PMG) and/or Speed Signal Generator (SSG) with other appropriate systems. • Replace mechanical speed control components with electronic digital controls.
Lack of Monitoring Governor Operating Data	• Cause of frequent unit trips unknown, resulting in unscheduled outages	• Add supervisory instrumentation system.
Generally Obsolete Governor	• Poor response, control below current standards • Automation not possible • Lack of spare parts	• Replace portions or the complete governing system. • For small units, possibly remove governor and replace with speed-no-load and shutdown solenoids. • For some units, only a gate positioner is required.
Governor Hydraulic System in Poor Condition	• Unit outages for repair • Decreased reliability in the event of emergency shutdown • Continuous cycling at pumps	• Replace defective components or complete hydraulic system. • Alternatively, replace hydraulic servomotor cylinders with linear electric actuators.

4.4.8 Turbine Inlet Valve (TIV)

The turbine inlet valve isolates the turbine from the penstock during turbine shutdown and may allow turbine maintenance to be performed without dewatering the penstock. The valve also provides emergency shutoff of the water flow if the turbine wicket gates fail to close or the downstream penstock ruptures. The inlet valve is normally designed to provide safe and reliable closure against the maximum turbine discharges at maximum output or runaway conditions.

The turbine inlet valve assessment considers leakage, operation, physical condition, and head loss. Operation and head loss are discussed in Section 4.5 "Performance and Operational Information".

Leakage

Valve leakage is measured with the valve in the closed position, upstream pressure acting on the valve and the downstream side dewatered. Leakage rates are generally a function of the head acting on the valve; however, maximum leakage often does not occur at maximum head. Valve leakage should be measured at a head within 20% of the design head. It is determined by measuring the accumulated water over a period of time. The measured leakage can be compared against the following leakage rates for new and used valves provided in Table 4-7. Previous test results/reports should be relied on for the purposes of the condition assessment. Otherwise, leakage tests can be done at the feasibility stage when life extension alternatives are chosen and optimized.

Table 4-7
Leakage Rates for New and Used Valves

	Butterfly Valve	Spherical Valve
Leakage in new condition	0.005 cu ft/min per ft of valve diameter	A few drops
	0.5 P/min per m of valve diameter	
Acceptable leakage in used condition	0.02 - 0.03 cu ft/min per ft of valve diameter	0.02 cu ft/min per ft of valve diameter
	2.0 - 3.0 P/min per m of valve diameter	2.0 P/min per m of valve diameter

If valve leakage exceeds these quantities, the valve seals should be replaced to minimize water loss and prevent progressively increasing seal damage.

Physical Condition

The physical condition of the valve components and systems may have deteriorated over the service life of the valve. Table 4-8 lists inlet valve deficiencies which may lead to operating problems and reduced reliability. Recommended remedies for these problems are discussed in Section 4.8.

Table 4-8
Turbine Inlet Valve Operating Problems

Deficiency	Possible Effect
Unreliable control system	Emergency closure no longer reliable
Incomplete valve closure	Excessive leakage may preclude turbine dewatering
Seal leakage	Increasing erosion and damage
Valve trunnions leakage	Trunnion bearing damage
Excessive corrosion	Reduced operating reliability
Defective operating mechanism	Vibration during valve operation

4.5 Performance and Operational Information (Records)

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information (Step 4-2, Volume 1)</td></tr>
<tr><td colspan="2">Risk Evaluation</td><td colspan="2">Assessment of Remaining Life</td></tr>
<tr><td>Condition Rating(if available)</td><td>Repairability Rating</td><td colspan="2">Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

4.5.1 Operational Information

An examination of operational information records should reveal how the turbine has been operated and any unusual circumstances encountered during its service life. Operating data should be interpreted very carefully as anomalies in data and data recording practices can lead to wrong conclusions on current turbine operation.

Operating data provides information on the level of use or loading on equipment. This has important implications on the remaining life of equipment. For example, equipment that runs at full capacity for most of the year may have a shorter life expectancy than low load equipment of the same age or, equipment used on a start/stop basis may have a shorter life span then base loaded equipment. Further, operation in rough zones (higher vibration load levels) impacts equipment condition.

The following Table 4-9 lists the parameters that are of interest for the assessment of condition and performance.

The collection of this information will allow current operating parameters to be compared to the original design parameters of the turbine. If the operating conditions have generally been different than the design conditions there may be benefits in optimizing the turbine design to suit the actual operating conditions.

Operational data also provides information on the performance level of equipment in terms of its reliability and availability. These performance measures can indicate areas where insufficient maintenance is affecting the output of the plant. Section 4.7, Volume 1 provides a description of the main performance indicators. For individual equipment condition assessment, dependability and performance (efficiency) are the most useful indicators. At the equipment level, equipment can also be evaluated on its contribution to plant flexibility i.e. how the equipment enables the plant to supply products such as peaking and synchronous condense capability and the importance of its reliability in supplying these products.

Table 4-9
Operational Data for Condition Assessment

The following operating data should be gathered and used as part of the assessment of condition and performance.

Current Generation Data	Original Design Data	Operating Modes	Current "Off-Design" Operation	Reliability Data
Generating hours	Gross head (m)	Base-load (%time)	High head (ft, m)	Number of System Disturbance Reports (outages), broken down by cause and the equipment to which the outage was assigned.
Synchronous condense hours	Tailwater level (m)	Peaking (%time)	Low head (ft, m)	Planned outages (% time), broken down by equipment areas
Speed-no-load hours	Maximum flow (cfs, cms)		Low flow (cfs, cms)	Forced outages (% time), broken down by equipment areas
Off-line hours (available but not operating)	Maximum output (MW)		Rough zone (hours)	
Turbine discharge (cfs, cms)	Maximum pump power for pump-turbine (MW)		Overgating (% time)	
Annual net energy (GWh)	Pumping losses for pump turbine (ft, m)		High sediment loadings (% time)	
Annual gross energy (GWh)	Pumped storage overall cycle efficiency (generating energy/pumping energy) for plants with a closed upper reservoir.		Runaway conditions	
Maximum output (MW)			Unusual occurrences (e.g. foreign objects entering the turbine)	
Average gross head (ft, m)				
Average net head (ft, m)				
Tailwater Level (m)				
Maximum headwater level (m)				
Maximum pump power for pump-turbines (MW)				
Pumping losses for pump-turbines (ft, m)				
Pumped storage overall cycle efficiencies (generating energy/pumping energy) for plants with a closed upper reservoir				

4.5.2 Turbine Performance

Turbine performance is the efficiency with which the turbine converts potential hydraulic energy to mechanical energy and is often represented by a graph of turbine efficiency curve versus flow or output, as shown in Figure 4-13 Also shown are typical turbine performance curves illustrating the relationship between modern performance, the original design, and a deteriorated turbine runner (noted as "present performance").

As previously indicated, turbine performance usually deteriorates over time because of increased runner seal, or tip, clearances or changes to the runner blade shape and/or deterioration in the surface finish of the runner, wicket gates and other turbine components. The original performance can be restored by repairing the affected hydraulic parts.

Table 4-10 shows a rough estimate of the decrease in turbine efficiency with age. Obviously, many other factors other than age contribute to the deterioration of efficiency over time. The type of materials used, the quality of design and the operational history of the unit are some of the key ones.

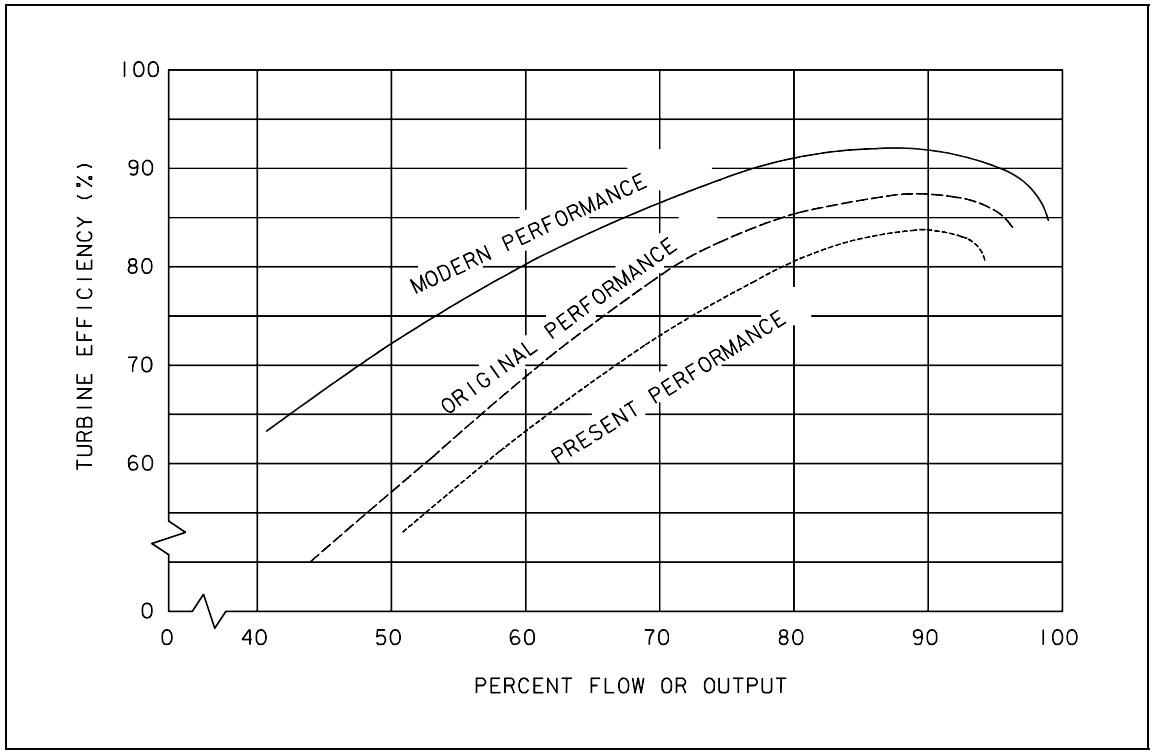

Figure 4-13
Sample Turbine Performance Curves

Table 4-10
Turbine Efficiency Change with Time[17]

Project[(1)]	Turbine Type	Reduction in Efficiency (%)	Years	Change in Efficiency/yr (%)
Plant #1, Unit #1	Propeller	-5.1	35	-0.146
Unit #2	Propeller	-0.8	35	-0.023
Unit #3	Propeller	-1.9	35	-0.054
Plant #2, Unit #1	Kaplan	-5.3	45	-0.118
Plant #3, Unit #2	Kaplan	-2.0	31	-0.065
Plant #4, Unit #1	Francis	-2.3	38	-0.061
Plant #5, Unit #1	Francis	-2.0	30	-0.067
Plant #6, Unit #1	Francis	-4.0	31	-0.129
Plant #7, Unit #1	Francis	-1.5	48	-0.031
BC Hydro Plant #1	Francis	-6.0	62	-0.097
BC Hydro Plant #2, Unit A	Francis	-0.75	24	-0.031
Unit B	Francis	-0.6	22	-0.027
Unit C[(2)]	Francis	+0.28	15	+0.019
	Average Propeller & Kaplan			-0.081
	Average Francis			-0.057

Note: [(1)] Plant names and unit numbers have been eliminated from the above table for confidentiality reasons.
[(2)] Recorded increase in efficiency is most likely a result of test uncertainty.

4.5.3 Assessment of Turbine Performance

The reduction in turbine efficiency over time is dependent on turbine operation, frequency of repairs, runner and wicket gate material properties and water quality. Site tests at different installations have indicated that the average efficiency loss over time can vary from almost zero to over 0.1% per year. Turbines which require significant cavitation repair or which operated in water with high solids content will tend to have a higher loss rate than those which have minimal cavitation damage and operate in relatively clean water. Frequent welding on the runners can gradually change the blade profiles and this can affect efficiency. The most significant impact on efficiency probably comes from increasing surface roughness of the hydraulic passages and increasing seal clearances. Seals should be maintained as part of regular planned maintenance. However, water passages such as the spiral case are usually not painted or cleaned on a regular basis and therefore increasing surface roughness is a more likely cause of efficiency loss. In the absence of other data, an efficiency loss of 0.05% per year can be used.

Tests of efficiency deterioration over time are quite sensitive to actual test uncertainty. Different test methods were used for many of the units in Table 4-10 and this can increase the uncertainty of the calculated efficiency deterioration to perhaps over 2%. The occasional results that indicate an increase in efficiency are probably due to the combined effect of the test errors and inaccuracies of the different test methods used.

[17] Personal Communication, P. Rodrigue, Acres International, January 2000

The performance of many older turbines was determined by site tests using the Gibson pressure time flow measurement test methods. By comparison with other test methods, it seems that older Gibson tests give efficiency values 1-2% higher than many other test methods. Figure 4-14 compares flow measurement results using different test methods.

Furthermore, when comparing the efficiency of modern turbines or turbine runners with the original turbine performance, it should be noted that the original turbine performance may have been overestimated and never confirmed by commissioning tests.

In estimating prototype turbine performance from the model test, many manufacturers prior to 1960 adjusted the test results for scale effect using the Moody step-up formula. However, it has since been concluded that this approach to step-up will usually overestimate prototype efficiency and an efficiency step-up of 67% of that calculated by the Moody formula is considered more realistic. As a result, many early manufacturer's prototype performance curves overestimated efficiency by perhaps 1% (depending on turbine size).

The performance of older turbines can be increased above that of the original design by modern runner designs. By comparing the existing turbine performance with the original and modern hydraulic performance, the benefits of turbine modernization can be determined. An example of a typical performance curve for a Kaplan turbine upgraded with a new runner is shown in Figure 4-15.

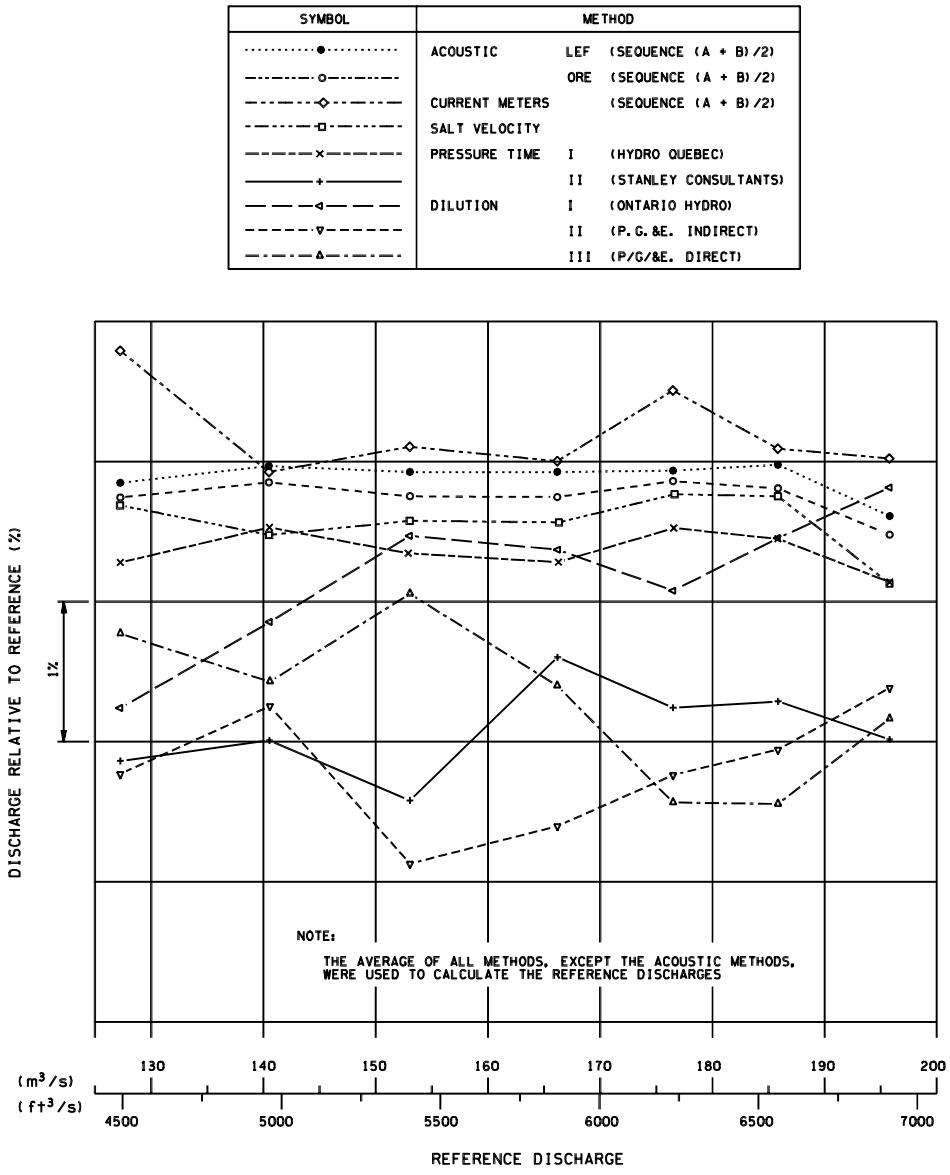

Figure 4-14
Comparison of Flow Measurement Methods
Reproduced from EPRI, Palo Alto, CA, 1986, FM-4367 "Comparison of Acoustic and Other Flow Measurement Systems: Kootenay Canal Test"

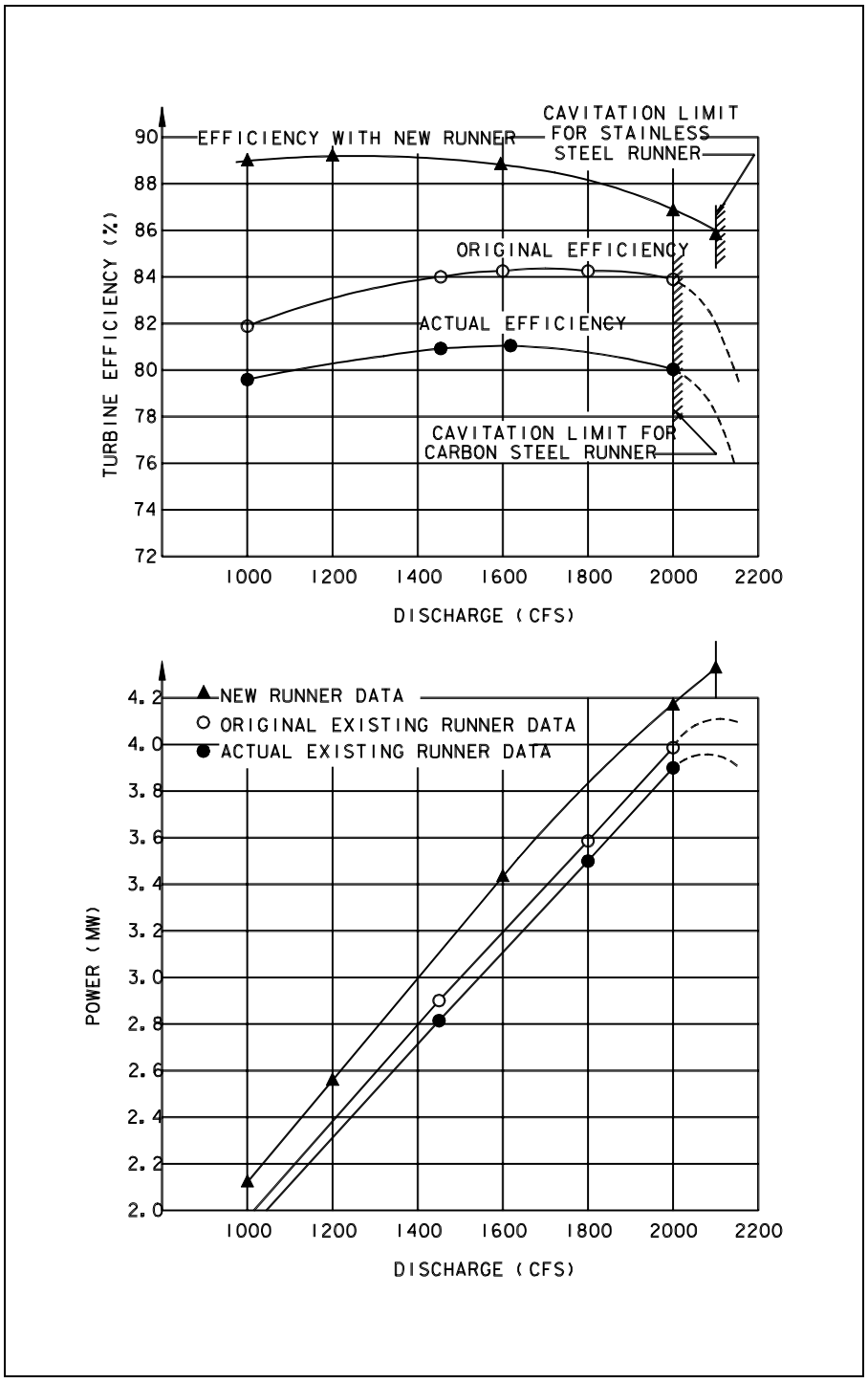

Figure 4-15
Sample Kaplan Turbine Performance Curves; Turbine Power and Efficiency of Original Design, Present Performance and Modern Performance

Energy losses in hydraulic turbines can be categorized as follows:

- Distributor (spiral case, stay vanes, wicket gates).
- Runner losses due to friction and flow disturbances.
- Runner seal loses due to disc friction and seal leakage.
- Draft tube losses due to friction and flow disturbances.

Typical loss diagrams for Francis and Kaplan turbines are shown in Figures 4-16 and 4-17 over the range of turbine output. As shown, the distributor, runner, and runner seal losses decrease as load increases while draft tube losses increase.

Losses in a Pelton turbine are approximately as follows:

- inlet pipe (distributor) and injector - 0.5 to 1.0%
- runner - 6.5 to 9.0%
- turbine housing - 0.5 to 1.0%

The lower losses are for a high head multi-jet turbine, whereas the higher losses are representative of a low head horizontal unit.

The losses in a pump-turbine are similar to a Francis turbine.

A discussion of hydraulic turbine design theory is beyond the scope of these Guidelines. A list of references is provided in Appendix A to provide a source of additional information on turbine efficiency.

Two recognized test codes exist for performing field efficiency tests of hydraulic turbines: the ASME Power Test Code for Hydraulic Prime Movers PTC 18 and the IEC International Code for Field Acceptance Tests of Hydraulic Turbines, Publication 41. The efficiency tests prescribed by these organizations may be too complicated to be used by an Owner's personnel, may require specialized equipment, and can be relatively expensive ($30,000 to $50,000 or more) to perform. Alternatively, simplified procedures can be used to assess the general performance of the existing turbine. Two potential methods include the comparison of turbine output and index tests. Testing methods are discussed in Section 7 of this Volume.

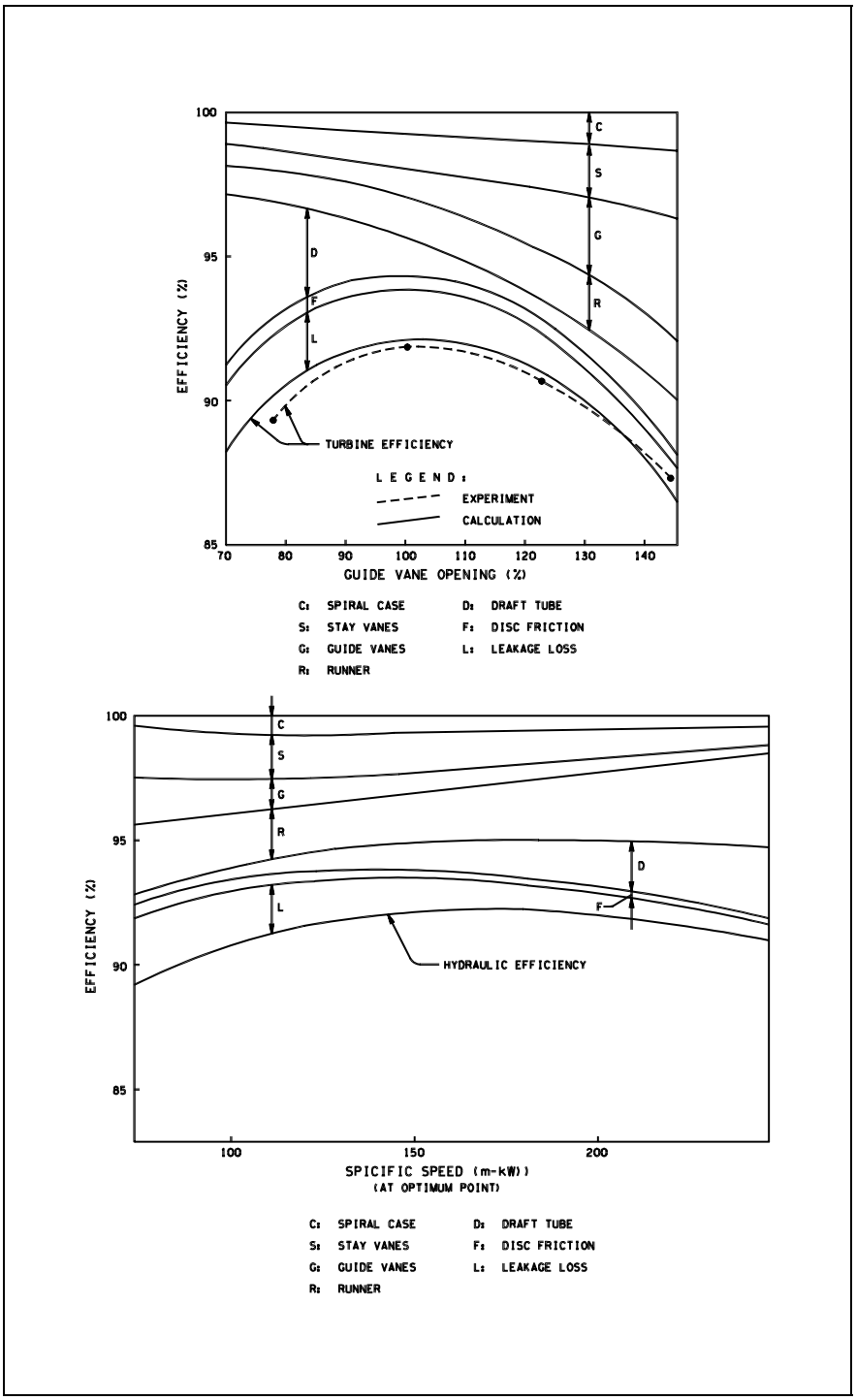

Figure 4-16
Loss Distribution of Francis Turbines
Reproduced from Hydraulic Machinery Book Series, Mei Zu-Yar, Editor, Avebury Technical, 1991, "Mechanical Design and Manufacturing of Hydraulic Machinery, Chapter 8: Structural Design of Hydraulic Turbines", H. Tanaka. Used with permission.

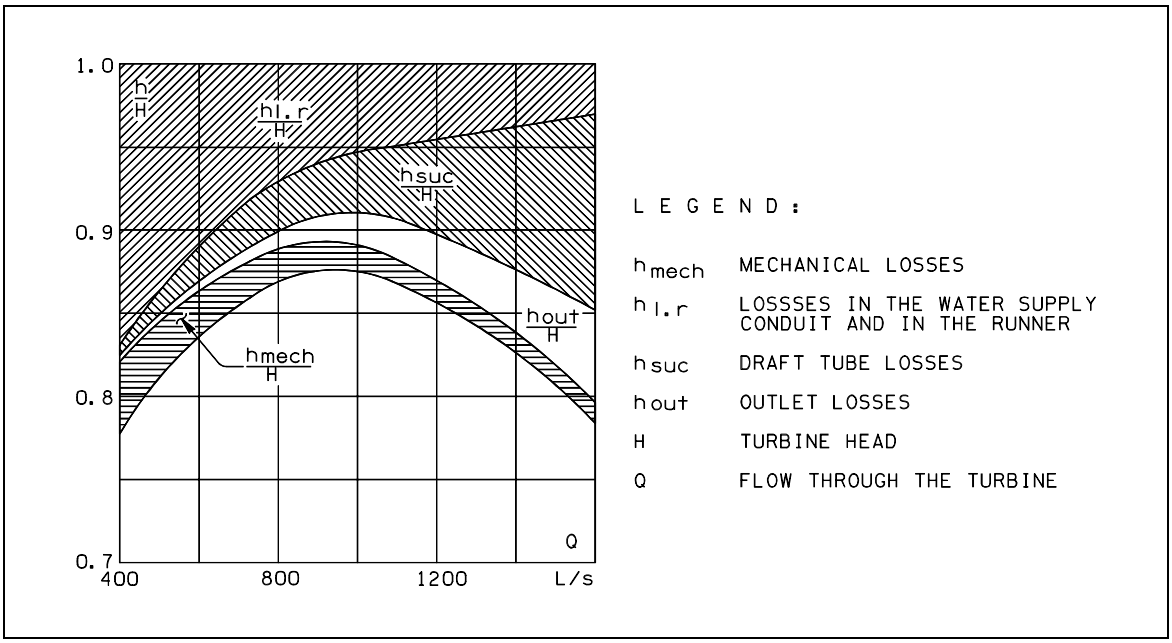

Figure 4-17
Loss Distribution of Kaplan Turbines
Reproduced from G.I. Krivchenko, translated from the Russian by S.M. Semenov and V.A. Kochin, MIR Publishers, Moscow, 1994 (CRC Press, Boca Raton, Fl), *"Hydraulic Machines, Turbines and Pumps." Used with permission.*

The performance of Kaplan turbines is dependent on operation with an optimum wicket gate-runner blade relationship. This is usually established by index tests, although the initial gate-blade relationship (or cam) can be based on model test results. The gate-blade relationship is controlled by the governor. If index tests have not been done on a Kaplan turbine for several decades, the unit should be retested to check the optimum gate-blade relationship. Adjustments should be made if necessary.

4.5.4 Nozzle Assemblies (Pelton Turbines)

For multi-jet Pelton turbines, where control of individual needles is possible, the optimum point to change from one to two to three, etc. needles can be determined by site index tests. This will ensure an efficiency as high as possible over a wide range of loads.

4.5.5 Governing System Performance

Speed Regulation and Stability

The speed regulation performance of the governor can be determined from observations of the unit frequency, speed indicator, and wattmeter. Evaluation and setting of governor performance characteristics is extremely complex and should only be undertaken by a governor expert. IEEE Standard 125 "IEEE Recommended Practice for Preparation of Equipment Specifications for

Speed - Governing of Hydraulic Turbines Intended to Drive Electric Generators" recommends minimum performance characteristics for governors.

The requirement for governing in a transmission system is dependent upon the performance requirements of the Regional Transmission Organization (RTO) or other regulatory councils such as the North American Electric Reliability Council (NERC), which is made up of ten regional councils. The governor characteristics must comply with the standards issued by these local authorities. Regular testing of governors and generators is often mandatory.

Governors are required on plants operated as isolated systems. Accurate governing may or may not be required for some plants if they are operated in a large and stable transmission system.

For mechanical governors, unstable operation may indicate the need to rehabilitate the governing linkage and hydraulic valves to eliminate friction and deadband inaccuracies which have developed because of wear. Unstable operation can also be caused by other factors such as excessive draft tube surging or resonance of the turbine, generator, and penstock frequencies. However, evaluation of these factors is beyond the scope of this section.

Needles and Deflector Timing

Deflectors are used to control unit speed during fast load changes on some units. The deflectors act quickly to direct flow away from the runner until the needles adjust to provide the correct flow. Needle/deflector timing should be checked. IEEE Standard No. 125 provides guidelines for deflector/needle speed regulation characteristics.

4.5.6 Turbine Inlet Valve (TIV) Performance

Operation

The closing time of the inlet valve should be checked to ensure that the closure time is as per the original design. Previous test results should be used if they are available. Otherwise testing should be done at the feasibility stage review of a project involving TIV rehabilitation or replacement. These tests are described in Section 7 of this Volume as a general review.

Head Loss

The head loss across the valve is rarely a factor that is considered when evaluating valve remaining life and life extension activities. It can be a consideration for modernization projects or discussed in Section 5.6.4.

4.6 Risk

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
<tr><td colspan="2">Risk Evaluation
(Step 4-4, Table 4-4, Volume 1)</td><td colspan="2">Assessment of Remaining Life</td></tr>
<tr><td>Condition Rating (if available)</td><td>Repairability Rating</td><td colspan="2">Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

The identification of risks, that the hydro plant is exposed to and which relate to life extension and modernization, is an integral part of the Plant Survey process. As discussed in Sections 2.3.2 and 4.4 of Volume 1, risks fall under three broad categories:

- Business critical risks, which relate to the consequences of catastrophic events.
- Life safety risks, which threaten workers and/or public.
- Financial risk, which relate to equipment failures and mis-operation.

The risk identification process is set out in Section 4.4, Volume 1. In essence, a reasoned, systematic approach is necessary to ensure that all risks are identified. Various standard methods exist to assist the user in risk identification. These include:

- Failure Modes and Effects Analysis (FMEA)
- Failure Modes, Effects and Criticality Analysis (FMECA)
- Hazard and Operability Study (HAZOP)
- Fault Tree Analysis (FTA)
- Event Tree Analysis (ETA)

FMEA

IEC Standard 300-3-9 describes FMEA as:

"… a technique, primarily qualitative although it can be quantified, by which the effect or consequence of individual component fault modes are systematically identified. It is an inductive technique which is based on the question "what happens if …?". The essential feature in any FMEA is the consideration of each major part/component of the system, how it becomes faulty (the fault mode), and what the effect of the fault mode on the system would be (the fault mode effect). Usually, the analysis is descriptive and is organized by creating a table or worksheet for the information. As such, FMEA clearly relates component fault modes, their causative factors and effects on the system, and presents them in an easily readable format."

FMECA

FMECA is an extended form of FMEA where each failure mode identified is ranked according to the combined influence of its probability of occurrence and severity of its consequences.

Further details on both FMEA and FMECA can be found in IEC Standard 812.

HAZOP

IEC Standard 300-3-9 describes HAZOP as:

"… a form of fault modes and effects analysis (FMEA). HAZOP studies were originally developed for the chemical industry. It is a systematic technique for identifying hazards and operability problems throughout an entire facility. It is particularly useful in identifying unforeseen hazards designed into facilities due to lack of information, or introduced into existing facilities due to changes in process conditions or operating procedures. The basic objectives of the techniques are:

- to produce a full description of the facility or process, including the intended design conditions;
- to review systematically every part of the facility or process to discover how deviations from the intention of the design can occur; and
- to decide whether these deviations can lead to hazards or operability problems."

FTA

IEC Standard 300-3-9 describes FTA as:

"… a technique, which can be either qualitative or quantitative, by which conditions and factors that can contribute to a specified undesired event (called the top event) are deductively identified, organized in a logical manner and represented pictorially. The faults identified in the tree can be events that are associated with component hardware failures, human errors or any other pertinent events which lead to the undesired event. Starting with the top event, the possible causes or fault modes of the next lower functional system level are identified. Following stepwise identification of undesirable system operation to successively lower system levels will lead to the desired system level, which is usually the component fault mode."

ETA

IEC Standard 300-3-9 describes ETA as:

"… a technique, either qualitative or quantitative, which is used to identify the possible outcomes and if required, their probabilities, given the occurrence of an initiating event. ETA is widely used for facilities provided with engineered accident mitigating features, to identify the sequence of events which lead to the occurrence of specified consequences, following the occurrence of

the initiating event. It is generally assumed that each event in the sequence is either a success or a failure."

At the completion of the risk identification process the user can determine, in accordance with the owner's risk tolerance standard what risks require mitigation and the cost of mitigation. The projects associated with mitigation can then be identified for inclusion in the summary of the Needs and Opportunities tables in Volume 1 (Tables 4-6 and 4-7 respectively).

Table 4-5 of Volume 1 is used to capture the results of the risk identification process.

4.7 Assessment of Remaining Life

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
<tr><td colspan="2">Risk Evaluation</td><td colspan="2">Assessment of Remaining Life
(Step 4-8, Volume 1)</td></tr>
<tr><td>Condition Rating (if available)</td><td>Repairability Rating</td><td colspan="2">Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

The prediction of remaining life is the most subjective element of the condition assessment. The aim is to replace, rehabilitate or upgrade equipment at the optimum point in the equipment's life cycle. The scheduling of these activities requires that the approximate year of equipment failure is predicted. Such predictions should be made by an experienced engineer.

Optimum time in this context means the time beyond which the impacts of not intervening will be greater in the long run than the impacts of intervening now. In terms of risk cost, this is the time when the risk costs are minimized. Risk costs include the costs of equipment replacement and the consequences of equipment failure (lost energy, collateral damage, cost increases for purchase or installation of new equipment due to working in an "unplanned" outage situation, etc.).

Most plant owners rely on equipment specialists to assess the remaining life of equipment. It should be noted that it is normal practice for these specialists to provide a conservative assessment of how many years the equipment will last until failure. This assessment says nothing about the optimal time for equipment replacement as discussed above. Often the terms remaining life and replacement time are used synonymously but they are in fact quite different concepts.

Under the auspices of the Canadian Electricity Association (CEA), a consortium of energy companies from both Canada, U.S. and abroad, have undertaken "remaining life" studies for hydro power equipment. The results of this project have been used to develop optimal equipment replacement strategies and computer software tools to assist with the prediction of remaining life and scheduling of equipment replacement. All costs associated with equipment replacement decisions are included in the methodology used to arrive at optimal timing for the equipment replacement.

Table 4-11 lists typical life expectancies for the major mechanical equipment covered by this section. This information, combined with the condition and performance assessment, can assist the engineer in determining an approximate remaining life for each piece of equipment. Comparison of similar equipment in a similar application is useful in estimating the typical service life of equipment.

Table 4-11
Life of Hydropower Plant Systems

Life of Hydropower Plant Systems		
Plant Systems	**Economic Life* (years)**	**Considerations which Affect Component Life**
Turbines		
Francis, Propeller	50	Safety of operation, leakage, cavitation damage, erosion, corrosion, cracks, decreased efficiency, technology level used in design
Kaplan	30-40	
Pelton	40-50	
Pump-turbines	25-33	
Other Mechanical Installations		
Gates, butterfly valves, special valves, cranes, auxiliary mechanical equipment	25-50	Quality of material, condition, safety of operation, quality of design, design stresses

* Economic life based on a 1975 study of SEV/Swiss Electrotechnical Association, and updated by more recent experience of BC Hydro.

A long-established rule of thumb is that hydro turbines have a useful life of 30 to 40 years. However, it is becoming increasingly obvious that this guideline will significantly underestimate the life of hydraulic machinery. While few in numbers, there are hydraulic turbines still operating which were installed in the late 1890's. Many owners of older hydroelectric units find it economically attractive to rehabilitate their equipment with the intent of obtaining at least 20 and sometimes 40 or more years of life from the equipment.

The concept of "remaining service life" is not always easy to apply to mechanical equipment. Certain equipment can be maintained indefinitely as long as parts for repair are available or can be made. In addition, some equipment can be repaired easily and brought back to original condition and performance level without a major rehabilitation project. An equipment's "useful life" can then be quite different than its service life. In other words, although the service life can be extremely long, there are a number of issues that would limit the equipment's useful life. These include:

1. Increasing maintenance costs to keep equipment "in service".
2. Increasing equipment unreliability and outage time associated with the increased maintenance requirements.
3. Increasing obsolescence of parts necessitating the costly manufacture of parts.
4. Maintenance problems associated with equipment of a "hybrid" structure after too many repairs and substitute parts have been installed to keep the equipment operational.

5. Equipment condition and performance have deteriorated to an extent that it cannot be repaired or rehabilitated to its original condition even though the equipment is still largely operational and can stay in service.
6. A change in operational conditions can mean that a piece of equipment is unable to meet the new requirements of the plant even though it is in relatively good condition.

Often equipment condition is not the driver for replacement and remaining service life is not a factor in the replacement decision. The real driver of equipment rehabilitation or replacement is the upgrade opportunity for increased performance (i.e. plant or system revenue) through increased power and efficiency. Sometimes, the opportunity to supply additional plant products such as peaking capability to capture high electricity rate periods or voltage support is the driver for equipment replacement.

A note should be made in the Equipment Condition Summary worksheet (Section 4.1) when "useful life" is the issue driving equipment replacement rather than "remaining service life".

Probabilistic models for predicting remaining life and optimal replacement timing are available, although the mathematics and analysis involved in using these models can be quite complex and time-consuming. The usual problem with trying to develop and use probabilistic models is the lack of data available on equipment age, history and condition. Furthermore, the presence of too many variables which affect the service life of equipment can make the model overly complex and impractical. The CEA has attempted to address many of these issues in their project that looks at the prediction of "remaining life" for hydropower equipment.

Pelton Runners[18]

The following is adapted from a Kvaerner (GE Hydro) course on maintenance and condition inspection of hydro equipment.

The buckets on a Pelton runner are subject to stress cycles with varying magnitude, and are therefore exposed to fatigue fracture. This lifetime depends, in addition to other factors, on the difference between the highest and lowest stress magnitude, as well as the number of cycles encountered. The lifetime is difficult to determine, but experience from larger Norwegian turbines indicates a fatigue life of 10^{10} cycles. A 5-jet turbine with 375 RPM will encounter $375 \cdot 5 \cdot 60 = 1.125 \cdot 10^5$ cycles/h, and will consequently be able to endure at least 89,000 hours of operation before there is a risk of fatigue fracture. This corresponds to almost 18 years with 5,000 hours of operation per year. Experience has shown that where Pelton runners require frequent repair and subsequent stress relieving because of erosion due to sediment, this life is reduced.

[18] Kvaerner Course (GE Hydro) III/6.2, November 13, 1986.

4.8 Life Extension Activities

Equipment Data and Technical Information		History of Maintenance and Major Repairs
Condition Assessment of Equipment		Performance and Operational Information
Risk Evaluation		Assessment of Remaining Life
Condition Rating (if available)	Repairability Rating	Environmental Issues
Possible Life Extension Activities (Step 4-5, Volume 1)		Timing and Costs of Life Extension Activities

The scope of hydro mechanical projects for a Life Extension and Modernization (LEM) Plan range from the rehabilitation of one or more components such as the runner to a complete turbine replacement. Table 4-3 in Section 4.4 provides a list of common life extension activities for each type of equipment.

The decision to replace a piece of equipment has an effect on the scheduling of other life extension activities typical for a piece of equipment over a 20 year planning horizon. For example, if the decision is made to replace a piece of equipment in 5 years, then typical life extension activities such as painting may be reduced in scope or eliminated altogether from the LEM Plan in the preceding years.

A sample LEM Plan for the turbine could consist of rehabilitating all critical turbine components. Table 4-12 is a sample minimum rehabilitation plan; however, if inspection and operation of the unit indicate the rehabilitation is not warranted, particular components can be excluded based on engineering judgement. While the full extent of the necessary turbine rehabilitation is often unknown until the unit is disassembled, usually 90% of the work scope can be determined with the unit assembled based on available data.

In general, turbine rehabilitation should not be required until after about 40 years of operation; however, this will vary considerably from unit to unit. Some units require disassembly after 10 to 20 years, while others have operated well over 50 years without major rehabilitation. The frequency of rehabilitation will depend on the unit design, the method of operation, and the general maintenance program for the equipment. Turbine operation would generally be considered unsatisfactory if dismantling for turbine rehabilitation is required more frequently than every 20 years.

Reversible pump-turbines, on the other hand, have a much more severe operating cycle because of frequent starts and stops, and significant pulsing forces on the wicket gates during pumping operation. Pump-turbine dismantling is often done on a more frequent basis than a "conventional" turbine (roughly every 10 to 20 years), as an overall preventive maintenance program for the equipment.

Table 4-12
Sample Minimum Turbine Life Extension (requires unit disassembly)

Component	Life Extension Activity
Turbine (General)	Disassemble/rehabilitate/reassemble.
Runner	Sandblast unmachined surfaces; NDT areas of high stress; inspect and repair any cracks; inspect and repair cavitation and/or erosion damage; measure and renew seal clearances if warranted; repaint if not stainless steel. Inspect/replace seals and bushings on Kaplan runners. Pelton runners with significant erosion repair will require stress relieving.
Wicket Gates and Wicket Gate Operating Mechanism	Sandblast unmachined surfaces; inspect and repair cracks, inspect and repair pitting and cavitation damage; grind rough areas, measure and renew bearing journals, bearings and seal contact surfaces if warranted; repaint if not stainless steel.
Shaft	Inspect for cracks and straightness; measure and renew bearing and shaft seal wear surfaces if warranted; install new shaft seal sleeve and/or renew shaft seal surface if warranted.
Guide Bearing	Inspect for scrapes/wiping cracks in babbitt surface; lack of bonding of babbitt to shell; rebabbitt and machine if warranted.
Head Cover and Bottom Ring	Sandblast unmachined surfaces; check for cracking; repair any cracks and pitting damage; line bore wicket gate bushing bores if warranted; measure and replace wicket gate bushings if warranted; measure and replace runner seal surfaces and wicket gate wearing plates if warranted; repaint.
Shaft Seal	Replace - if warranted.
Discharge Ring (Kaplan and Propellar) and Stay Ring	Sandblast unmachined surfaces; NDT stay vane fillet areas; inspect and repair cavitation and cracks; dimensional check sealing surfaces and repair and remachine if warranted; repaint.
Spiral Case and Draft Tube Liner	Sandblast; inspect and repair damage, inspect and repair fitting and drain connections, repaint.
Servomotor	Disassemble, inspect for wear and repair; replace piston rings, packing, and refinish cylinder bore, if warranted.
Instrumentation	Check instrumentation. Update and modernize if justified
Alignment	Check alignment; re-align if warranted.

4.8.1 Runner

The following are the life extension options available for the runner:

Replace:	-	new runner design (increased efficiency and/or output with less cavitation)
Repair:	.	
General	-	weld cavitation damage; apply more cavitation resistant coating
	-	weld erosion damage
	-	reprofile blades
	-	weld cracks
	-	repaint
Kaplan - specific	-	replace/repair blade bearings
	-	replace/repair blade servomotors
	-	addition of anti-cavitation lips (on propeller turbines also)
	-	As a last resort, weld-up adjustable runner blades so that they are fixed in one position. This could have a negative impact on unit efficiency and output.

Repair or Replace

Turbine runner alternatives include either rehabilitating or replacing the existing runner. The runner can be replaced with a comparable runner to regain original output and efficiency (life extension) or with a new runner having a modern hydraulic design, higher efficiency or output (modernization) and less cavitation. A significant cost in runner replacement is disassembly, reassembly, and, therefore, lost generation. Because of this, once the decision to disassemble the turbine is made, modernization of other aging components may also be feasible.

Regaining the efficiency difference between the existing and original runner is possible by either repair or replacement of the runner. Methods to estimate the possible efficiency gain are presented in Section 5 of this Volume and for this analysis can be assumed to be uniform over the entire load range. Similarly, the efficiency gain can be multiplied by the average annual generation to determine the generation impact and benefit. Analyses of the generating benefits and costs are provided in Section 6.

The decision to repair or replace the runner made of a weldable material is usually based on economics. The costs of repair are weighed against the cost of a new runner and any benefits that a new runner has in terms of increased efficiency/power and less cavitation. Although the deteriorated condition of the existing runner may warrant replacement for structural reasons, justification can still be made on an economic basis by evaluating the cost of extensive repairs. Repair of runners constructed of cast iron or other materials which are difficult to weld should usually be excluded for purely technical reasons.

Repaint/Recoat[19]

The following information is taken largely from Thomas Spicher's "Hydro Wheels: A Guide to Maintaining and Improving Hydro Units," 2nd Edition which is a useful reference on the topic of coatings.

There are many types of coatings to apply to the runner in order to reduce cavitation, corrosion or erosion.

The main categories for coatings are:

- coal tar based coatings
- vinyl resin base paints (filled resin and rubber-like materials e.g. urethane rubber)
- ceramic metals, epoxy-like materials (non-fused coatings)
- metallic materials (applied using flame, arc or plasma spray processes)
- weld overlay

Non-metallic coatings are widely and effectively used for simple corrosion prevention. Coatings that can be applied with a trowel are used for shaping, and rubber-like materials are used to provide cavitation and abrasion resistance.

Epoxies and ceramic mixed coatings provide little cavitation resistance, except for some fused metallic coatings and rubber-like compounds. It is sometimes possible to reduce cavitation by contouring with epoxies and similar filled resins. Fillers applied by flame or plasma spray also have a favorable track record for cavitation control.

Coating suppliers can provide information on the available coatings for different applications. However, references on the successful use of coatings on similar applications are very valuable when trying new products.

The load conditions at the plant in particular determine which coating types are most applicable. As with many cavitation-limiting techniques, there can be a compromise between unit efficiency and cavitation control if blade contouring is employed.

Paint and other thin coatings on the wicket gates and runner do not significantly impact cavitation performance unless they are of sufficient thickness to alter the form or contour of the surface.

[19] Thomas Spicher, *"Hydro Wheels: A Guide to Maintaining and Improving Hydro Units"*, 2nd Edition, 1997 Update, HCI Publications, Kansas City, 1997.

Stainless Steel

Stainless steel runners and wicket gates are generally left unpainted to take advantage of the corrosion resistance of the material. However, ASTM A743 CA-6NM (13Cr - 4N:) stainless steel, which is commonly used for runner castings, is susceptible to rapid corrosion if it has been contaminated with carbon from grinding or weld spatter.

The corrosion resistance of the stainless steel can sometimes be restored by passivating the surfaces.

Carbon Steel[18]

Although one of the most versatile and effective coating for carbon steel runners and wicket gates has been red lead priming paint, it is no longer an acceptable solution because of its environmental implications. Government environmental regulations must be followed when removing red lead paint. This can add to the time and cost of rehabilitation work.

Vinyl resin is used as a coating for runner and hydraulic passages at many facilities. The vinyl resin can be supplied in white which greatly enhances visibility in the turbine. However when it is heated the vinyl resin can generate toxic fumes and must be thoroughly removed prior to weld repair.

Coal tar epoxy can be used successfully as a wicket gate coating but often loses adhesion and peels off under high velocity flow.

Epoxy Phenolic coatings may provide better bonding, corrosion and abrasion resistance for future runner and hydraulic passage applications but experience with these coatings is limited.

For units which must pass large concentrations of sand and sediment, neoprene coatings are reported to significantly extend runner life of carbon steel and bronze runners.

Cavitation Repairs[19]

The repair of cavitation pitting damage on turbines is an essential part of a hydro plant life extension. If left unrepaired, or if improperly repaired, the extent of damage will increase, at an accelerating rate, eventually leading to an extended and costly outage of the unit.

For the life extension plan, repair work will be more comprehensive than the repair work conducted under the turbine's maintenance program. An effective repair program can minimize the adverse problems associated with cavitation pitting. The main objects of such a program are:

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[18] U.S. Bureau of Reclamation, "*Turbine Repair, Facilities Instructions, Standards and Techniques, Volumes 2-5"*

[19] U.S. Bureau of Reclamation, "*Turbine Repair, Facilities Instructions, Standards and Techniques, Volumes 2-5"*

- restoration of runner and other components within the turbine water passages to "as new" condition;
- correction of any profile errors or irregularities which are responsible for the pitting; and
- avoidance of blade shape distortion and its affect on further damage.

As with any equipment, excessive repairs to a turbine can lead to reduction in its performance and useful operating life. Extensive weld repairs can result in runner blade distortion, acceleration of further cavitation damage, and possible reduction of turbine efficiency. Also, extensive repair can cause residual stressing in the runner resulting in structural cracking at areas of high stress.

The frequency of turbine cavitation repairs will vary from plant to plant. The time between repairs will depend upon the rate of metal removal, the plant owner's philosophy for repairs, and other indirect factors.

Various approaches for cavitation repair developed by plant owners include:

- Making all repairs during each inspection period. Many plant owners believe that this is good practice from a preventive maintenance point of view.
- Repairing all areas where cavitation damage is 1/8 inch (3 mm) or deeper. Preparation of damage areas even with only light surface "frosting" is usually done to depth of at least 1/8 inch (3 mm).
- Repairing areas on stainless steel overlay where pitting is 1/8 inch (3 mm) or deeper. On carbon steel, repair areas even with light damage using stainless steel weld material.
- Allowing cavitation to progress to the maximum depth which can be repaired with two weld passes (about 3/8 inch [10 mm])
- Making repairs only when damage becomes so bad that it threatens to impair the strength of the turbine or when preparation of the damaged area may result in holes completely through the runner blade. This is not recommended as the impact of stress levels is unlikely to be known.

It is not possible to give specific recommendations for frequency of cavitation repairs because each plant or unit should be evaluated on an individual basis. In deciding on whether or not to make repairs, the following factor should also be considered.

- The repair cost per pound of weld material will decrease as the amount of material increases because of fixed set-up time. This favors a longer period between repairs. However, if the cavitation pitting characteristics are such that cavitation damage tends to accelerate, increasing the time between repairs may substantially increase the amount and cost of repairs which must be made.
- If the time between repairs is lengthened, additional care will be needed to prevent distortion because of the increased amount of weld material to be added. Blade distortion may adversely influence unit performance, reduce the life of the runner and increase future cavitation damage.

- If repairs are made on a more frequent basis, they may be completed within the time frame required for other maintenance work on the unit. If repairs are delayed, an extended outage or a specific outage for cavitation repairs may be necessary, resulting in reduced availability and possible lost generation or capacity benefits.

When the decision is reached to proceed with cavitation pitting repairs, it is necessary to determine the method to be used for repairs and whether or not blade profile corrections should be made. The various methods for undertaking repairs include:

- Fill damage area with weld material
- Fill damage areas with non-fused material (such as ceramic materials)
- Weld plates over the damage area

Remove damage section and replace with new forged plates welded in place.

The general applicability of these methods are summarized in Table 4-13.

Table 4-13
Methods of Cavitation Pitting Repair

	Weld Repairs	Non-Fused Material	Weld Plates Over Damaged Area	Remove Damaged Area and Weld Plate Insert
Propeller and Kaplan Turbines				
- Runner blades	X	X		X
- Hub	X	X	X	
- Wicket gates	X	X		
- Discharge ring	X	X		X
- Draft tube liner	X	X		X
Pump-Turbines and Francis Turbines				
- Runner blades	X			X
- Crown	X	X	X	
- Band	X			
- Wicket gates	X	X		
- Discharge ring	X	X		X
- Draft tube liner	X	X		X

Tables 4-14 to 4-16 outline possible methods of reducing cavitation damage.

Prior to making repairs, consideration should be given to the options available for doing the work. There are two general approaches:

1. to restore the runner to original profiles; and the other;

2. to perform runner modifications to eliminate or reduce the cause(s) of the damage. Restoration to original profile is the most straightforward approach; however, in the long term, profile modifications will likely have increased benefits.

Crack Repair

Cracks may appear which are caused by localized residual stress or solid objects striking the blades of the unit. Records should be kept on the locations and lengths of these cracks. A crack can relieve the residual stress and no further cracking will develop. Holes drilled at the ends of the crack, a procedure known as stop drilling, will often arrest the growth of the crack.

Table 4-14
Cavitation Pitting Location[20]
Francis Turbines

	Location of Pitting	Possible Cause of Pitting	Possible Remedial Measures(1)
Runner			
A.	Suction side of blade near band and truing edge	- overall pressure too low - improper blade contour or profile	- reduce output - correct contour or profile
B.	Leading edge of blade near band on suction side	- operation at heads much higher than design - improper leading edge profile	- modify leading edge profile if head range is normal (2)) - modify leading edge profile
C.	Leading edge of blade near band on pressure side	- operation at heads much lower than design - improper leading edge profile	- modify leading edge profile if head range is normal. (2) - modify leading edge profile
D.	Trailing edge of blade on suction side	- improper trailing edge contour	- adjust contour
E.	Crown or leading edge of blade near crown	- operation for extended periods at low load	- reduce low load operation
F.	At air vents in crown	- discontinuity at crown	
Discharge Ring			
G.	On discharge ring opposite runner band	- seal leakage cavitation	
Draft Tube Liner			
H.	Under bottom of band	- seal leakage cavitation	
I.	Below band	- seal leakage cavitation - cavitation vortices shed from trailing edge of blade - vortex originating at leading edge of blade during low load operation	- reduce maximum load - reduce low load operation
Wicket Gates			
J.	Pitting on side of wicket gates	- improper contour - leakage cavitation - galvanic corrosion between stainless steel sealing insert (overlay) and carbon steel	- modify contour - see Note 3

Notes:
(1) Remedial measure common to all types of damage is to make repairs using material of greater cavitation resistance than the original material.
(2) Normal head range for a Francis turbine is from 25% below to 10% above the rated head.
(3) On high head installations, avoid extended operation with wicket gates in closed position. Use turbine inlet valve in automatic start-stop sequence.

[20] U.S. Bureau of Reclamation, *"Turbine Repair, Facilities Instructions, Standards and Techniques, Volumes 2-5"*

Table 4-15
Cavitation Pitting Location[5]
Propeller and Kaplan Turbines

	Location of Pitting	Possible Cause of Pitting	Possible Remedial Measures(1)
Runner			
A.	Suction side of blade from centerline to trailing edge	- overall pressure too low (setting to high) - improper blade contour or profile	- reduce maximum output - correct contour or profile
B.	Leading edge of blade on suction side	- operation at heads much higher than design - improper leading edge profile	- modify leading edge profile if head range is normal (2) (3)
C.	Leading edge of blade on pressure side	- operation at heads much lower than optimum	- modify leading edge and profile if head range is normal (2) (3)
D.	Trailing edge of blade on pressure side	- too abrupt a profile change at trailing edge	- make a more gradual taper to the trailing edge of the blade
E.	Blade periphery on the suction side of the peripheral edge of blade	- leakage cavitation	- add anti-cavitation lips
F.	Near blade periphery on suction side of blade (vertical Kaplan turbines)	- discontinuity between runner periphery and discharge ring when blades are at steep angle.	
G.	Hub	- operation for extended periods at low load - discontinuity between blade and hub (Kaplan turbines)	- reduce low load operation
Discharge Ring			
H.	Discharge ring	- leakage cavitation - cavitation vortices or wakes shed from lower trailing edge of wicket gates	- add anti-cavitation lips - modify wicket gate lower trailing edge
Draft Tube Liner			
I.	Draft tube liner	- leakage cavitation - cavitation vortices shed from trailing edge of runner blades - too abrupt a contour change between the discharge ring and draft tube liner	- add anti-cavitation lips - modify runner blade trailing edge.

Notes:
(1) A remedial measure common to all types of damage is to make repairs using a material of greater cavitation resistance than original material.
(2) Normal head range for propeller turbines is from 10% below to 10% above the design head.
(3) Normal head range for Kaplan turbines is from 35% below to 25% above the design head.

[5] U.S. Bureau of Reclamation, *"Turbine Repair, Facilities Instructions, Standards and Techniques, Volumes 2-5"*

Table 4-16
Cavitation Pitting Location[5]
Pump-Turbines (Francis)

	Location of Pitting	Possible Cause of Pitting	Possible Remedial Measures(1)
Runner			
A.	Suction side of blade near band and pump leading edge	- overall pressure too low - improper blade profile or contour	- correct contour or profile
B.	Suction side of blade at pump leading edge	- operation at heads much higher than design (or discharge lower than design) - improper leading edge profile - improper trailing edge profile for turbine operation	- modify leading edge profile if head range is not excessive (2)) - modify leading edge profile - modify trailing edge profile
C.	Pressure side of blade at pump leading edge	- operation at heads lower than design (or discharges higher than design) - improper leading edge profile	- modify leading edge profile if head range is not excessive (2) - modify leading edge profile
D.	Suction side of blade near band at turbine leading edge	- operation in turbine direction at head much higher than design - improper leading edge profile	- modify leading edge profile if head range is not excessive (3) (4) - modify leading edge profile
E.	Pressure side of blade near band at turbine leading edge	- operation in turbine direction at heads much lower than design - improper leading edge profile	- modify leading edge profile if head range is not excessive (3) (4) - modify leading edge profile
F.	Crown or turbine leading edge of blade near crown	- operation for extended periods in turbine direction at low loads	- reduce low load operation
Discharge Ring			
G.	On discharge ring opposite runner band	- seal leakage cavitation	

[5] U.S. Bureau of Reclamation, *"Turbine Repair, Facilities Instructions, Standards and Techniques, Volumes 2-5"*

	Location of Pitting	Possible Cause of Pitting	Possible Remedial Measures[1]
Draft Tube Line			
H.	Under bottom of band	- seal leakage cavitation	
I.	Below band	- seal leakage cavitation - cavitation vortices shed from trailing edge of bucket (turbine direction) - vortex originating at leading edge of blade during low load operation	- reduce load in turbine direction - reduce low load operation
Wicket Gates			
J.	Pitting on side of wicket gates	- improper contour	- modify contour
		- wicket gate leakage	- see Note 5
		- galvanic corrosion between stainless steel sealing insert (or overlay) and carbon steel	

Notes:

1. A remedial measure common to all types of damage is to make repairs using a material of greater cavitation resistance than the original material.
2. Normal head range for a pump-turbine in the pump mode is:

ft. (m)	Head Range
<1500 (457)	5% below to 7% above design head
1500 - 3500 (457 - 1067)	5% below to 10% above design head
>3500 (1067)	5% below to 20% above design head

3. Normal head range for a pump-turbine in the turbine mode is typically from 15% below to 20% above the design head; however, it is also dependent on the pump selection.
4. Turbine leading edge modifications will change pump mode characteristics and, therefore should be discussed with the manufacturers.
5. On high head installations, avoid extended operation with wicket gates in closed position. Use inlet valve in automatic start-stop sequence.

A specialist should investigate and recommend crack repair options. Any crack longer than 2 inches should be removed and repaired provided that the runner consists of a weldable alloy.

Reprofiling

If identical cavitation patterns occur on several blades, blade re-profiling may be a solution. Reprofiling includes changing the blade entrance angle, blade leading edge shape, blade thickness, blade discharge angle and trailing edge shape or the contour angle of the blade to band fillet. For example, if the blade entrance angle is too sharp or the blade leading edge is too blunt, severe cavitation can result. A specialist or the manufacturer should investigate and recommend any reprofiling activity. "Hydro Wheels - A Guide to Maintaining and Improving Hydro Units" by T. Spicher provides details on how cavitation damage can be repaired using blade reprofiling techniques. The following draws heavily from this report.[21]

It is important to note that changing blade profiles may eliminate cavitation in one area by simply moving it downstream to another, perhaps even more critical area. Modifications to the blade leading edge to reduce cavitation on the one side will likely make the opposite side of the blade more susceptible to cavitation damage; therefore, change must be made carefully.

Early assessment of the effects of the profiling on cavitation is vital. Profiling can affect:

1. cavitation patterns on runner
2. unit efficiency
3. severity and location of cracking
4. unit vibration or "roughness"

Input from the turbine manufacturer is essential in making runner blade modifications. Except for small adjustments, the changes may influence the performance of the machine. This is especially true for pump-turbines where blade modifications at the turbine leading edge will affect pump discharge and pump leading edge modifications will influence turbine performance.

Reprofiling and other runner modifications require a thorough analyses and understanding of the cause of the cavitation pitting and/or the mechanism for efficiency improvements. Basically, four types of modifications may be necessary to reduce the damage:

- Leading edge modification
- Training edge modification
- Profile changes
- Addition of anti-cavitation fins (on propeller and Kaplan turbines)

[21] Thomas Spicher, *"Hydro Wheels: A Guide to Maintaining and Improving Hydro Units"*, 2nd Edition, 1997 Update, HCI Publications, Kansas City, MO 1997

Air Injection

Air injection into the runner area either by natural aspiration or using low pressure compressors (blowers) is another method that can be used to reduce cavitation. This approach should be discussed with the turbine manufacturer or specialist engineer as air injection can have a negative impact on efficiency.

Kaplan Blade Bearings and Seals

Repair or replacement of the blade bushings, seals and servomotors may be required on a Kaplan unit. Servomotor repair or replacement options would be similar to those for the wicket gate servomotors (Section 4.8.2).

4.8.2 Wicket Gates and Wicket Gate Operating Mechanism

The following are the life extension activities available for wicket gates and wicket gate operating mechanism:

1. refurbish bearing journals on the wicket gate stems to reduce friction (mitigate problems with governor capacity) and leakage
2. replace wicket gates
3. replace bushings
4. grinding, painting, welding and metal spray ("void filling") to improve surface finish
5. replace seals
6. refurbish or replace servomotors

Repair wicket gate surface corrosion is not required for structural regions until the pitting depth exceeds approximately 3/16" (5 mm), depending on the gate material thickness. However, to reduce friction losses, repair may be made earlier. For efficiency purposes, the gate surfaces should be retored to "as new" condition.

General repair procedures may include:[22]

- Machine surfaces to sound metal not less than 0.125 inch (3 mm) deeper than the finished dimension.
- Rebuild surfaces using welding techniques for maximum bond strength.
- Remachine the surfaces to the manufacturer's original contour and surface finish.

[22] U.S. Bureau of Reclamation, *"Turbine Repair, Facilities Instructions, Standards and Techniques, Volumes 2-5"*

- If the wicket gate stems are worn at the bearing journals, they may be refurbished with welding followed by machining or by machining and then sleeving the stems.
- If wicket gate bushings are worn beyond manufacturer's tolerances they can be replaced with self-lubricating bushings although some plant owners prefer traditional bronze bushings.

New wicket gate bushings must be line bored or the headcover and bottom ring bores line-bored and close tolerance bushings procured. Unless otherwise specified by the manufacturer the bushings should be plumb and concentric within 0.00005 multiplied by the vertical distance between the top and bottom bushings.

Tables 4-14 and 4-16 in the previous section provide a summary of the causes of wicket gate cavitation and possible remedial measures.

Self lubricated bushings eliminate the need for periodic greasing. These bushings would be required in locations where water quality standards prohibit contamination by even small quantities of grease. There are numerous self-lubricating bushing materials on the market and several have been in use for over 20 years. Care should be exercised in the selection and application of any self-lubricating bushing. See Section 4.10 for further information on self-lubricating bushings.

The bearing journals on many wicket gate stems are of carbon steel material. If self-lubricated bushings are installed, stainless steel journals are usually required. This would necessitate journal refurbishment by welding or sleeving as mentioned above.

4.8.3 Nozzle Assemblies and Deflectors

The wear surfaces on the Pelton turbine nozzle assemblies are generally the needle tip and nozzle, in particular the seat ring. These components are primarily subject to erosion due to sediment. They are repaired by machining or grinding the damaged surface, applying stainless steel weld overlay and re-machining to their finished contour. The other option is to replace them if damage is severe.

Thermal sprayed coatings such as sprayed tungston have been quite effective in reducing erosion damage on nozzles and needles. However, such coatings should not be used where the water is sediment-free as the finish surface is rougher compared to polished stainless steel, resulting in some decrease in efficiency.

The life extension activities typical for the deflectors are:

1. repair of the deflector impact surfaces

2. replacement of the bushings and seals on the deflector shaft

Repair of needle and deflector servomotors would be similar to the repair of wicket gate servomotors.

4.8.4 Other Turbine Components

This section covers the following turbine components:

- spiral case
- stay ring/stay vanes
- discharge ring (Kaplan/Propeller)
- headcover/bottom ring

The following are the main categories of life extension activities available for these turbine components:

a. repaint/recoat

b. refurbish

c. detection of and welding of cracks

d. replace

Discharge Rings (Kaplan/Propeller)

Wear on the discharge ring is not usually a problem on Francis turbines. Discharge rings are replaced if cavitation and corrosion are severe or are in areas that are difficult to repair from an access point of view. This can be a major project on large units. On Kaplan or propeller units, it is also common to machine down the existing discharge ring (by site machining), apply a layer of stainless steel weld metal (by automated welding) and then finish machining the repaired surface.

Table 4-15 provides a summary of the causes of cavitation on discharge rings and possible remedial measures.

Seal and Wear Rings (Stationary and Rotating Rings)

Wear rings are designed to be replaced.

Turbine seal ring replacement or re-machining is usually scheduled to coincide with major unit overhauls requiring disassembly. Generally seal ring replacement is required before seal characteristics reach 200% of design clearance. As seal ring clearances increase beyond 200%, significant efficiency losses can be expected as well as changes in the hydraulic downthrust of the unit which can lead to bearing damage.

Usual practice is to select dissimilar materials with different hardnesses for stationary and rotating ratings to resist galling and seizure in the event the rings make contact. The materials selected must also have good cavitation erosion, corrosion and abrasion resistance.

Various material combinations are possible; one successful combination for general service has been:

Stationary wear ring:	Nickel Aluminum Bronze, UNS C95500
Rotating seal ring:	Austenitic Stainless Steel, UNS S30400

If a runner is being replaced and the existing stationary wear rings on the headcover, bottom or discharge ring are in reasonably good condition, but slightly out of round, it should be possible to machine the existing wear ring in place. The final runner machining must suit the new diameter of the machined stationary ring.

Coatings

A general discussion of coatings is provided in Section 4.8.1.

4.8.5 Turbine Shaft, Shaft Seal, and Guide Bearing

The following are the life extension activities available for the turbine shaft:

a. re-machine journal

b. re-align

c. install a new shaft seal sleeve of stainless steel material.

The following are the life extension activities available for the shaft seal:

a. replace shaft seal wear elements

b. repair/replace shaft seal wear surface (shaft sleeve or wear plate)

The following are the life extension activities available for turbine guide bearing:

a. replace

b. rebabbit

Shaft Seal

The shaft seal wearing parts are designed to be replaced. In some cases where experience with the existing shaft seal is unsatisfactory, a complete new seal design is provided. Traditional stuffing box type seals with graphite packing are sometimes replaced with a low maintenance seal utilizing a plastic wearing surface. Carbon seals are sometimes similarly replaced.

Guide Bearing Rebabbitting

Minor scratches on the babbitt can often be adequately restored by scraping. However, periodically, due to lubrication failure, normal wear, or lack of bonding at the babbit-bearing shell interface, the bearing must be rebabbitted to restore design clearance and surface finish. This requires removal of the bearing.

4.8.6 Governing System

The following are the life extension activities available for the governing system:

(a) Rehabilitate existing governor
- rebuild ballhead motor (if applicable), pilot valve/servo valve and servo-feedback linkage
- replace/repair components (pumps) of the hydraulic pressure supply system
- remagnitize PMG

(b) Convert mechanical governor to an electro-hydraulic governor.
(c) Replace governor with a digital governor.
(d) Replace governor with a gate positioner.

Maintain and Update the Existing Governing System

Many of the governors for older hydro turbines still operate as well as when they were first installed. Therefore, any plans for life extension may consider using the present governing system, even if the turbine is being uprated. The decision to maintain the existing governing system when other unit components are uprated should be based on the following:

- Reliability - ensure that the governing system provides reliable, safe shutdown of the turbine under operating and emergency conditions.
- Capacity - confirm that hydromechanical capacity of the governor system is sufficient to meet the uprated turbine conditions.
- Performance - Confirm that the design level of response to load changes, stability, and existing startup time is maintained.
- Increase Wicket Gate Opening - As discussed in the turbine section, increasing the turbine output might often be accomplished by increasing the wicket gate opening using the available margin provided in the servomotor stroke or by modifying the servomotors. The governor will not be unduly affected by a moderate increase in maximum wicket gate opening if the governor capacity, as determined by the capacity test procedure, is not exceeded. There is likely enough adjustment in the linkage to accommodate changes.
- Availability of Spare Parts - Spare parts should be available for the foreseeable future.
- Maintenance - Confirm that the maintenance costs for the governor, including the hydraulic pressure system, are not escalating.

Converting a Mechanical Governor to an Electronic Governor

Typically, converting a mechanical governor to an electronic governor is warranted if the mechanical governor head is deteriorated, because of wear of the moving parts, causing the governor stability and response time to deteriorate. Replacement by an electronic governor head will restore and improve the speed sensing capability of the governing system. Additionally, a new governor head would improve the governor reliability and response in the event of unit load rejection and overspeed. Although older, mechanical governors, which were designed for manual operation and control, can be automated by adding auxiliary devices required for remote monitoring and control, modifying or reconditioning existing mechanical governors to facilitate plant automation is not recommended, especially if replacement parts must be custom-made.

Replace the Existing Governor with a New Governor

Replacing the existing governor should include both technical and economic considerations. Typical reasons for replacement include insufficient governor capacity and incompatibility with new turbine equipment. For many obsolete governing systems, spare parts are no longer available. Thus, replacements are expensive and often must be made by the Owner's maintenance staff. Because manufacturers no longer manufacturer or service these systems, a complete overhaul of an existing governor may exceed 50% of the cost of a new governor, thus providing a strong economic incentive for replacement.

Modern governors and electronic controls can enhance the capability of units to operate at maximum efficiency or to maintain constant discharge, under changing head conditions.[23] Modern, digital equipment can greatly reduce the human effort in operating and monitoring a hydro plant while enhancing reliability. Some rehabilitation and upgrade projects have focused primarily on governors and controls.

Older governors typically operated a lower pressures than today's modern, high-pressure governors. Converting to a higher pressure usually requires significant cost to replace the distributing valve, servomotors, piping, pumps, pressure tank, and governor air compressor. Conversely, if the hydraulic unit requires replacement, it is generally more economic to install a new high pressure system which in turn necessitates a new governor.

New governors which can interface with new computer control equipment also offer the potential to improve water and power management. These economic benefits should be evaluated when comparing costs of the new system with the existing governing system.

In general, the dimensions of replacement governors are usually smaller than the existing governing components because of the use of miniaturized electronics and a higher pressure oil system and the absence of mechanical linkages. As a result, governor components can usually be located within the space of the original equipment with modifications to the piping and electrical connections.

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[23] O.Moeller, Panel Session (audiotaped): "Rehabilitation II - Lessons Learned," Hydrovision '98 Conference Reno, NV (July 1998).

Replace the Existing Governor with a Gate Positioner

Some generating units are so small in comparison to the system that they are electrically connected so that they cannot contribute significantly to system frequency control. In this case, a governor may not be required. Instead, a gate actuator or positioner may be used to position the flow-controlling devices to produce the desired output. If a synchronizer is used, it produces commands to raise and lower the actuator to control speed before and during synchronizing. [24]

A gate positioner may be a more cost effective solution for governor replacement in some applications, particularly in a multi unit plant. For example in a plant with 10 Kaplan units, only 2 of the units may need a control system that regulates wicket gate opening and runner blade angle. The rest of the units can be block loaded and the two units with control systems used to optimize water use.

Installation of a gate positioner rather than a governor should be considered in the context of the overall generating unit controls. With modern governors the speed control and other governor features are typically software installed on a commercial model PLC or computer. Therefore the added cost for a full governor may not be significant, particularly if the unit controls are being upgraded.

4.8.7 Turbine Inlet Valve

Valve Rehabilitation

The cost of valve rehabilitation is dependent on the specific condition and design of the existing valve. Factors affecting valve condition are the materials, provisions for replacement parts, type of service, water quality, extent of maintenance, and years of service. As a result, the rehabilitation alternatives can cover a fairly wide range.

Complete valve rehabilitation could consist of the following:

- Disassembly and shipment to the shop.
- Sandblast to sound metal.
- NDT shaft/trunnions, valve disc/rotor and valve body.
- Excavate and remove defects.
- Weld repair any defects in nonmachined parts.
- Remachine or weld overlay mating parts.
- Replace removable bearings and seals.
- Paint and corrosion protection.
- Reassembly, delivery, and installation.

[24] American Society of Mechanical Engineers, Hydropower Technical Committee, HCI Publications, Kansis City, MO 1996, ISBN 0-9657765-0-9, *"The Guide to Hydropower Mechanical Design"*

Another option is to install a more reliable control system. Replacing an existing hydraulic system with a newer or more reliable counter-weight system can improve the valve closure reliability by providing a more fail-safe emergency closure mechanism.

Table 4-17 lists the rehabilitation/upgrading options available if the condition assessment of the valve indicates that certain deficiencies should be corrected.

Table 4-17
Rehabilitation Measures for TIV's

Deficiency	Rehabilitation/Upgrading Measures	Results
Unreliable control system	Replace hydraulic and electrical control system	Restored/improved reliability
Seal leakage	Change valve seal and/or seal material	Reduced clearance and leakage, increased life, less maintenance; unit unwatering and maintenance work in the turbine may be easier.
Valve trunnions leakage	Replace trunnion bearings and seals	Improved fit and reduced vibration; self-lubricating bearings are more environmentally friendly
Poor valve operation	Provide automatic bearing lubrication	Reduced maintenance
Poor valve condition	Complete rehabilitation	Renewed life and reliability; Prevents progressive deterioration and reduces head loss.

Valve Replacement

Depending on the results of the valve condition assessment, replacement of the existing inlet valve may be warranted if valve deterioration is severe. If the turbine is being upgraded, a new larger valve to match the new turbine output may be considered as part of the overall LEM Plan. However, the value of valve replacement depends on:

1. cost of a new valve vs. the cost of rehabilitating the old valve;
2. the value of the reduction in head losses;
3. the downtime and resultant costs associated with valve replacement.

4.9 Timing, Schedule and Costs of Activities

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Condition Assessment of Equipment</td><td colspan="2">Performance and Operational Information</td></tr>
<tr><td colspan="2">Risk Evaluation</td><td colspan="2">Assessment of Remaining Life</td></tr>
<tr><td>Condition Rating(if available)</td><td>Repairability Rating</td><td colspan="2">Environmental Issues</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities
(Step 4-8, Volume 1)</td></tr>
</table>

4.9.1 Assigning Activities

The condition assessment should provide the early framework for a Life Extension and Modernization (LEM) Plan. Equipment maintenance, rehabilitation and replacement activities have been identified and now need to be organized into a 20 year (or other planning horizon) plan. Before specific activities can be assigned to a particular year in the LEM Plan, certain policies and guidelines on the assignment of activities must be established. The following are some of the questions that must be answered:

1. Is the general philosophy concerning life extension and modernization opportunities one of consolidation? i.e. try to do as much work as possible during an annual shutdown? This would be the philosophy if lost revenue due to shutdowns was high and over-shadowed the capital requirements for the actual work.

2. Are there limits on the capital available in any one year? This may limit the scope of work for a particular year even though there would be benefits to combining work activities instead of completing them over several years.

3. Is there a preference in maintaining a constant level of annual expenditure and staffing? i.e. life extension and modernization activities should be spread out to avoid years of very high capital requirements and to level out staffing requirements?

Once these questions have been answered, the life extension and modernization activities can be scheduled over the required planning horizon on both technical and financial factors.

Probabilistic models have been developed to assist with determining optimal timing of equipment replacement before failure. These can be quite complex and are only valuable if sufficient data is available to populate the model.

4.9.2 Major Unit Overhauls

An evaluation of the existing levels of maintenance and whether or not they are adequate must be made. Major overhauls or rehabilitation projects are usually required at regular intervals. An optimal schedule of unit overhauls must be established and the associated costs inserted directly into the LEM Plan.

4.9.3 Equipment Lead Times

Equipment lead time for large, complex or project specific equipment which has a long order time is an important factor in scheduling activities for the LEM Plan.

Runner

The lead time for procurement of a new runner depends on whether or not model tests are being performed and also on the size of the runner. Approximate lead times are given below. These exclude planning, bidding and contract negotiations.

Hydraulic design and model test	3 - 12 months
Design, manufacture and delivery	
- Large runner (greater than 13 ft (4 m) diameter)	9 to 15 months
- Small runner (less than 13 ft (4 m) diameter	6 to 12 months
Installation (including unit dismantling)	
- Large runner	2 - 4 months
- Small runner	1.5 - 3 months

The installation times assume that the complete generator and turbine must be dismantled for runner installation. If the installation involves other life extension activities (e.g. wicket gate bushing replacement, generator stator rewind, etc.) the total dismantling and installation time can increase, and a unit outage of up to 6 months is possible.

On turbines where the runner can be removed and installed without dismantling the generator (i.e. horizontal units, or vertical units where the runner is removed from between the spiral case and generator or from the draft tube core area), runner installation time can be shortened to a few weeks or even days, depending on the runner size and turbine type and design. Small Francis turbines and many Pelton units in particular are often designed to permit rapid runner changes.

Governor

The lead time required for governor modernization depends upon the degree of replacement. The following typical durations are provided to assist in scheduling the work. These are net times from purchase order, excluding planning, bidding and contract negotiations:

Rehabilitation of Mechanical Governor	2 months
Rehabilitation of Hydraulic System (excluding servomotors)	3 months
Replacement of Standardized Governor Components	
Design	4 weeks
Manufacture	4 weeks
Installation (depending on component)	1 to 4 weeks
Total:	9 to 12 weeks

Replacement of Customized Governor

Design	2 to 4 months
Manufacture	6 to 10 months
Installation	2 to 3 months
Total:	10 to 17 months

Turbine Inlet Valve

Figure 4-18 shows the delivery time required from the purchase order to delivery, installation and commissioning of new nonstandard butterfly and spherical valves. The delivery schedules shown include a completely redesigned valve, plus any additional corrosion protection, and are estimated as a function of valve diameter.

The time required for complete inlet valve rehabilitation including disassembly, shipping, rehabilitation, replacement of defective parts, corrosion protection, and re-assembly can be estimated to be four to six months. Alternatively, performing valve repairs using on-site machining to substantially reduce the rehabilitation time is often cost-effective and should be considered.

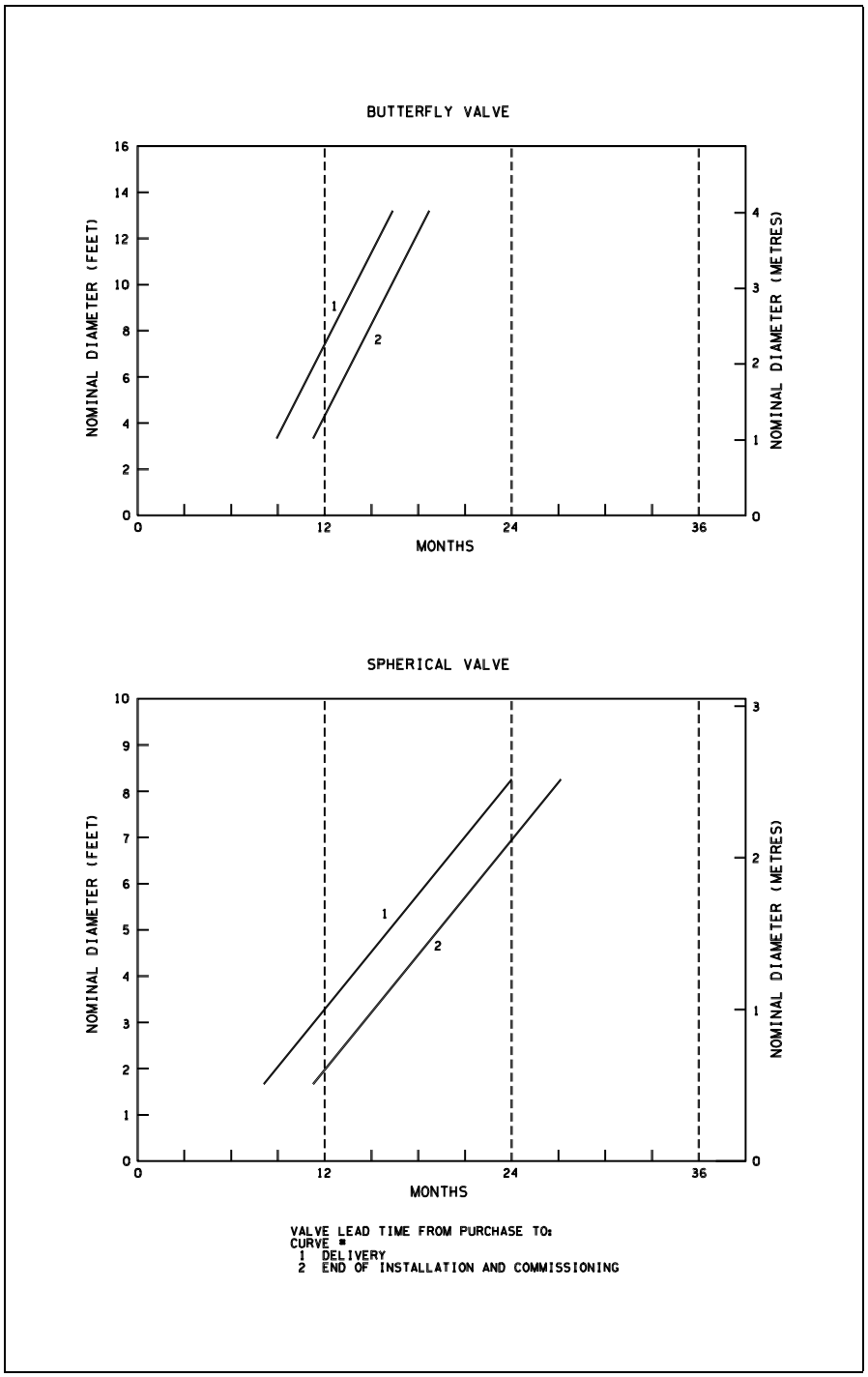

Figure 4-18
Delivery and Installation Times for New Nonstandard Valves

4.10 Environmental Issues

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
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(Step 4-6, Volume 1)</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

The purpose of Section 4.10 is to briefly identify some of the environmental issues that apply specifically to projects involving hydromechanical equipment. Environmental issues surrounding hydro plant projects can be very complex and a detailed explanation of all hydro plant environmental impacts is beyond the scope of these Guidelines.

The information provided in this Section is organized so that the following can be identified for the plant hydromechanical equipment:

a. the environmental issues that drive some life extension or modernization activities

b. the life extension activities that can be implemented to manage the environmental issues associated with hydromechanical equipment

c. the impacts of life extension activities implemented specifically to manage the environmental issues.

The following Table 4-18 is a general summary of the environmental issues and life extension activities discussed in Section 4.10.

Table 4-18
Environmental Issues - Hydromechanical Equipment

Section	Environmental Issues	Life Extension Activities to Potentially Address Environmental Issues	Impacts of Certain Life Extension Activities
4.10.1	Contamination of water by oil and grease	• Use environmentally friendly lubricants • Install containment systems (sumps, oil/water separator, etc.)	• Reduces risk of oil contamination of waterstream where used
		• Use self-lubricating materials (greaseless) for: wicket gate bushings; wicket gate operating linkages; turbine blade operating linkages; turbine blade trunnion bushings; turbine bearings	• Eliminates risk of oil contamination of water stream where used
		• Install oil-less governors (electric) • Use high pressure hydraulic systems	• Less oil (smaller volume) needs to be stored at plant
4.10.2	Low levels of dissolved oxygen in water that passes through turbine	• Implement auto-venting turbines	• Raises level of dissolved oxygen in water that passes through the turbine
4.10.3	Fish mortality	• Install fish-friendly turbines	• Reduces fish mortality
4.10.4	Reservoir issues - public safety, recreational use, habitat degradation, etc.	• Implement changes in water use	• See Table 4-19 in Section 4.10.4

Section 4.10 does not cover impacts associated with construction activities during implementation of the project. Guidelines on how to manage environmental considerations during implementation are provided in Section 8.

The International Organization for Standardization (ISO) Standard 14000 for implementing effective environmental management systems is an international standard designed for individual companies to set their own environmental goals and commitments to environmental policy. ISO 14000 guides the company to formulate a plan and carry out a policy to identify significant activities that affect the environment in the production of a good or service. The company then trains personnel in environmental practices, and creates an internal audit review system to ensure the program is implemented and maintained. A registration audit by a third party may be carried out, and subsequent surveillance audits may be conducted to maintain registration. An alternative method is for a company to perform an internal review and evaluate itself for conformity with the standards.[20]

As highlighted in a 1998 EPRI Journal article, worldwide movement or accreditation in all sectors of industry is increasing.[21] The power industry is no exception. The ISO 14000 Info Center reports that 11% of the US companies registered as of June 1998 represent the power/utility sector. The framework of ISO 14000 is a flexible set of criteria, which is aimed at improving the process of environmental management. The criteria encourage setting goals and seeking ways to implement and measure progress towards achieving better environmental performance. Further information on the ISO certification process can be found on the ISO web site: www.iso.ch.

4.10.1 Using Environmental Solutions to Lubrication

The Environmental Issue

In many jurisdictions, there is a "zero tolerance" policy for oil/grease contamination of water. No grease or oil is allowed to enter the water stream and any contaminated water must be contained in a sump. The contaminated water must then be treated (for example through an oil/water separator) before being discharged to the environment.

Many life extension activities are implemented into LEM Plans in order to address this issue. As listed in Table 4-18, life extension activities related to oil/grease water contamination fall into two main categories:

1. the use of environmental lubricants
2. mechanical equipment solutions.

[20] EPRI, Palo Alto, CA, W05715-01 December 1998, "Hydropower Technology Round-up Report", Part 1 *"Using Environmental Solutions to Lubrication"*

[21] "Environmental Management with ISO 14,000", EPRI Journal, March/April 1998, p. 24

Whichever life extension alternative is chosen, it must be entered into the LEM Plan as a defined project with cost and timing information.

The following discusses these life extension activities in more detail.

Life Extension Activities - Definition and Impacts

a. Environmental Lubricants[22]

The use of environmental lubricants is one approach to enhance environmental compliance when planning mechanical life extension or modernization projects. Lubricants - a broad term - includes fluids, meaning lubricating oils and hydraulic fluids, as well as greases.

To date no jurisdiction has established a law or standard that clearly defines the attributes of an environmentally safe fluid. Moreover, U.S. Federal Regulations do not accept the term "environmentally acceptable lubricant". Therefore, the federal and state standards for implementation of a spill prevention and countermeasure control plan apply and a spill (of an "environmentally acceptable lubricant") must be reported as if it were a conventional lubricant. However, it is expected that there would be some cost savings associated with clean-up of an environmentally acceptable spill, because of the characteristics of the lubricant.

Three types of "environmentally acceptable lubricants" are commercially available each with different properties:

- Crop oil derivatives based on natural esters-such as rapeseed oil, canola oil, and oleic acid esters - commonly used in the food industry.
- Synthetic esters, made from modified animal fats and vegetable oils
- Polyglycol lubricants (the first biodegradable oils on the market).[23]

Synthetic lubricants promise highly increased replacement cycle times and superior performance over vegetable-based lubricants (not necessarily hydraulic fluids). These lubricants may be economical over the longer term due to improved maintenance.

Manufacturers offer customized formulations for specific applications, and include additives for anti-foam performance and for improved temperature range application.

Switching to environmentally acceptable fluids may require special measures or adaptations to the system including: very thorough draining; different coatings, filters, and seals; more frequent filter changes; and adding moisture scavengers and temperature controls.

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[22] EPRI, Palo Alto, CA, W05715-01, December 1998, *"Hydropower Technology Round-up Report", Part 1, "Using Environmental Solutions to Lubrication"*

[23] *"Time for Change? Assessing Environmentally Acceptable Lubricants"* A.D. Beitelman, U.S. Army Corps of Engineers, Construction Engineering Research Laboratory, Hydro Review, April 1998, p. 46

b. Equipment Solutions

Some environmental solutions to lubrication are:

1. The use of self-lubricating materials (eg self-lubricating or greaseless wicket gate bushings).[24]

2. The use of oil-less (electric) governors with no requirement for oil storage or potential for oil leaks.

3. Installation of higher pressure governor systems which minimize the volume of stored oil.

4. Installation of oil/grease containment systems such as sumps, pumps and oil/water separators.

i. Self-Lubricating Materials[25]

The incorporation of greaseless, or self-lubricating, bearings and bushings has been applied worldwide, owing to increased environmental pollution concerns and overall reductions in long term bearing-related maintenance costs.

As noted in the Hydro Vision 96 Operations Best Practices Survey, 53 different hydropower producers reported the following:[26]

- 76% of the respondents identified bearing oil analysis as one of the prime indicators for scheduling hydro units for overhaul.
- 43% of the respondents installed greaseless bushings as part of a major overhaul

A variety of manufacturers have produced self-lubricating materials for applications in mechanical equipment. Self-lubricating materials incorporated into bearings surfaces, by their nature, negate the use of oil or grease. In the literature, the "self-lubricating" terminology is interchangeable with "greaseless bearings". Self-lubricating bushings are generally in the form of metallic (bronze) bushings with solid lubricant incorporated into their structure, or are made with a low wear, low friction coefficient polymer material (with or without a metallic backing).

The key advantage of self-lubricating bearings include:

- No requirements for ancillary lubrication systems

[24] Edward Fulton, Hydro Review, November 1998, *"Preparing for the Twenty-First Century: Environmental Protection Efficiency"*

[25] EPRI, Palo Alto, CA, December 1998 WO5715-01, "Hydropower Technology Round-up Report", Part 1 "*Using Environmental Solutions to Lubrication"*

[26] J.A. Jones, U.S. Army Corps of Engineers, R.A. Palyluk, Powertech Labs Inc., *Greaseless Bushing for Use in Hydropower Applications*. Final Report, Program, Testing and Results. U.S. Army Corps of Engineers, Hydroelectric Design Centre, Portland, Oregon, Rev. 1.0. 6/3/98.

- Reduction in operating and maintenance costs
- Elimination of environmental risk for lubricants being released into the water

Applications include:

- Turbine wicket gate stem bushings - upper, intermediate and lower
- Wicket gate operating ring and linkage
- Turbine blade operating linkage
- Turbine blade trunnion bushings

Some savings are realized in the maintenance costs of lubrication systems, including monthly or quarterly testing and avoided costs for replacements, cleanup and disposal. Some self-lubricating bushing types have been around for 20 years and are proven technology. However, care must be taken in selecting the right bushing type for a certain application. Problems with self-lubricating bushings on some large units have been experienced, due to selection of the wrong bushing type.

A discussion of a rating system for selection of the appropriate self-lubricating bushings is provided in EPRI's report "Hydropower Technology Round-Up Report; Using Environmental Solutions to Lubrication," December 1998.

ii. Electric (oil-less) Governors or Use of High Pressure Oil System

The use of electric (oil-less) governors is slowly increasing, particularly in Japan. See Section 5.4.3 for details. Both oil-less governors or the use of high pressure hydraulic systems minimize the amount of oil that needs to be stored in the plant.

iii. Containment Systems

Containment of water that has the potential to be contaminated with oil or grease is a very common environmental management solution. Typical arrangements include a system that collects water in a sump and then pumps this water through an oil/water separator before discharging it to the environment. Sumps must be adequately sized to contain the entire volume of oil that could be spilled and the estimated water volume in the sump at the pump shut-off level. Two pumps are often installed with each pump capable of pumping the estimated inflow.

4.10.2 Maintaining Dissolved Oxygen Levels

Environmental Issue

The problem of total-dissolved oxygen levels in water that passes through the turbine has been under study for decades. Achieving desired oxygen levels is more difficult in locations where water temperatures are higher because of the lower saturation levels of the dissolved oxygen.

Life Extension Activities and Impacts

Injection or aspiration of air into the turbine runner area is a common method of increasing dissolved oxygen levels. The air mixes with the water as it leaves the runner and passes through the draft tube, and the water absorbs the air, raising the amount of dissolved oxygen. The goal is to achieve increased oxygen with minimal efficiency decrease (or compressor power if a compressor blower is used to inject air). The system can usually be quantified on the basis of pounds of injected oxygen per kWh, where the kWh is the lost energy.

In recent years through a joint development effort, TVA and Voith are developing an auto-venting Francis turbine. With specially shaped turbine components, the turbine draws air from aeration outlets in the turbine water passage. Initial results from the first tests are promising in terms of aeration-induced unit efficiencies losses, reduction in vibration and cavitation and increases in dissolved oxygen levels downstream. Further research is still required.[27]

4.10.3 Improving Passage of Migratory Fish Through the Turbine

The Environmental Issue

In some particularly environmentally sensitive areas, the issue of fish mortality can drive many life extension projects in terms of equipment replacement and operation. Fish mortality can result from both water quality problems or the actual passage of fish through the turbine.

Life Extension Activities and Impacts

Turbines that reduce impacts on migratory of fish are being developed. These turbines:

a. use less water to generate the same power
b. have a greater distance between runner blades and longer water column
c. have a minimum gap where the blade meets the hub between the discharge ring and blades.
d. have fish sensors and a control system to limit the turbine operation to "fish friendly modes" when fish presence is sensed.

The Advanced Hydropower Turbine System Program (AHTS), which is a consortium of DOE, EPRI and the Hydropower Research Foundation with Voith Hydro Inc., is developing new fish-friendly design criteria for Kaplan and Francis turbines which would minimize fish injury, maximize efficiency and be more environmentally friendly.[28 & 29]

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[27] R.K. Fisher, P.A. March, D. Mathur, F. Sotiroporlos, G. Frank, presented at HydroVision 98, Reno, NV. August 1998,*"Innovative Environmental Technologies Brighten Hydro's Future".*

[28] R.K. Fisher, P.A. March, D. Mathur, F. Sotiroporlos, G. Frank, presented at HydroVision 98, Reno, NV. August 1998,*"Innovative Environmental Technologies Brighten Hydro's Future".*

[29] US Department of Energy, Idaho Operation Office, July 1999, *"A Summary of Environmentally Friendly Turbine Design Concepts".*

Two teams worked under the program. The DOE/Voith team approach was to improve existing runner designs. The ARL/NREC team approach was to design a totally new turbine runner.[9]

The new fish-friendly designs developed by the DOE/Voith team are described below[9]:

Kaplan turbines:

a. high efficiency (smooth flow)
b. minimum gap runners
c. reduced wicket gate overhang
d. hydraulically smooth stay vanes
e. environmentally friendly lubricating fluids and greases (greaseless wicket gate bushings)
f. placement of wicket gates behind the stay vanes
g. advanced control systems to maintain fish friendly operation and high efficiency

Francis turbines:

a. aeration to increase dissolved oxygen content (see Section 4.10.2)
b. reduced number of blades
c. thicker blade edge
d. reduced wicket gate overhang
e. environmentally friendly lubricating fluids and greases (greaseless wicket gate bushings)
f. operation of turbine at adjustable speeds
g. smooth surfaces on stay vanes, wicket gates and upper draft tube cone
h. advanced control system
i. minimization of pressure changes

The new runner designed by the ARL/NREC team is derived from a single-bladed impeller design for a screw/centrifugal pump, the pump type originally adopted to move delicate food items with minimal damage and more recently used to pump fish safely around diversion structures and bypass systems at several hydro facilities in the US. The design has evolved to a two or three-bladed runner.[30]

4.10.4 Change in Unit Operation

The Environmental Issue

Changes in plant water use are related to:

a. the amount of water spilled vs. the amount use for generation.

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[9] "Innovative Environmental Technologies Brighten Hydro's Future", R.K. Fisher, P.A. March, D. Mathur, F. Sotiroponlos, G. Frank, Voith Hydro Inc. presented at HydroVision 98, Reno, NV, August 1998

[30] U.S. Department of Energy, Idaho Operation Office, July 1999, *"A Summary of Environmentally Friendly Turbine Design Concepts"*

b. reservoir levels

c. the number of unit stop/starts

d. plant minimum and maximum discharge

The environmental issues surrounding such water use changes can be very complex and are beyond the overview level review of environmental issues covered in this Section.

Life Extension Activities and Impacts

Changes in unit/plant operation are often not regarded as life extension activities because they do not involve the repair or replacement of existing equipment. However, operational changes do require planning and testing and have tangible costs associated with their implementation. These "projects" must be entered into the LEM Plan because they very often have an impact on plant generation or other plant products which ultimately affect the financial evaluation of the plant.

Operational changes can also be the result of other life extension activities, for example, turbine rehabilitation work that restores the unit to its original capacity level.

The change in plant water use due to changes in unit operation, or more often, uprating of units, can have significant environmental impacts and associated licensing issues. The following Table 4-19 is a checklist of changes that can result from a life extension project involving operational changes (which may need an environmental assessment) and the possible environmental impacts:

Table 4-19
Potential Impact

Change in Water Use \ Potential Impact		Change in reservoir spill (Increase or Decrease)	Change in reservoir elevation	Change in Number of Unit Stops and Starts; Change in use of Unit's Synchronous Condensing Capability	Change in Generation (increase or decrease in unit flows)
Barrier to Fish Passage[1]					
Fish Mortality	Entrainment				
	Stranding				
Habitat Degradation[2]					
Change in Water Quality[3]					
Contamination of Local Drinking Water					
Bank erosion, sedimentation					
Change in Navigability					
Change in Recreational Use and Aesthetics					
Damage to Private and Public Lands)[4]					
Public/Boater Safety Concerns					
Other				Pressure wave of start-up may kill fish; may allow fish to move into penstock or draft tube if shutdown and synchronous condensing	Decrease in generation may allow fish to enter the draft tube; if turbine is run at an inefficient power level, turbulence of the water flow can increase leading to increases in fish mortality; increases in generation can cause foaming of the water.

1. Barriers to fish passage can be related to the following: velocity, debris, tributary access, man-made barriers.
2. Habitat degradation includes aquatic, terrestrial or riparian degradation.
3. Change in water quality can include changes to the following: total gas pressure (TGP), total suspended solids (TSS), turbidity, temperature, oxygen, mercury, biomethylation.
4. Damage to private and public lands can include the following: erosion, flooded wells, stranded water intakes, etc.

4.11 Input to Life Extension Plan (Section 4, Volume 1)

The condition information collected using the technical data of this volume is needed to develop a list of life extension activities for the plant hydro mechanical equipment. These activities and estimate costs are entered in Table 4-3, 4-4 and 4-5 of Volume 1, Section 4 as the "seed data" for a life extension plan for the plant. This collated information is one part of the data that populates the economic/financial model (Section 4, Volume 1) used to evaluate the impact of life extension projects on station profitability and cash flow.

Refinement of the life extension plan is an interactive and ongoing process. As the projects proceed to feasibility stage, costs are refined. Some initial results from the model may indicate which projects have the largest effect on plant economics in the near future. The timing of these projects may need to be optimized based on the initial cash flow estimates from the model.

The essential purpose of Section 4 was to identify those technical projects that must be undertaken in order to extend the life of the plant. How these projects are scheduled and funded involves collaboration between the financial planners and the engineers so that optimal project scopes can be defined for the identified life extension activities.

5
POTENTIAL FOR IMPROVEMENTS

5.1 Introduction

Section 4 of Volume 2 outlines a methodology to assess the present condition and performance of the hydromechanical equipment and provides input to the life extension portion of the Life Extension and Modernization (LEM) Plan. Section 5 provides input to the modernization portion of the LEM Plan. It provides information on assessing the upgrade opportunities that are available for hydromechanical equipment to improve plant performance beyond historical levels.

Figure 5-1 shows how the sub-sections of Section 5 contribute to the identification and assessment of modernization opportunities for the LEM Plan for the entire plant.

During the condition assessment of the hydromechanical equipment, the life extension requirements of equipment are identified. When significant life extension work in the form of rehabilitation or replacement is required, an informed decision needs to be made concerning whether modernization is warranted (the term "modernization" and its synonyms are defined in Section 2). Upgrading of equipment is complex as modernization of one piece of equipment often has implications on other plant equipment and the desired benefits may not be realized because of other plant limitations.

Appendix B in Volume 1 of these guidelines provides a general discussion on how to identify modernization opportunities. Modernization opportunities are classified into the following main categories:

- energy
- portfolio services - i.e. capacity, storage, river system regulation, etc.
- ancillary transmission services
- operational flexibility
- automation
- other services

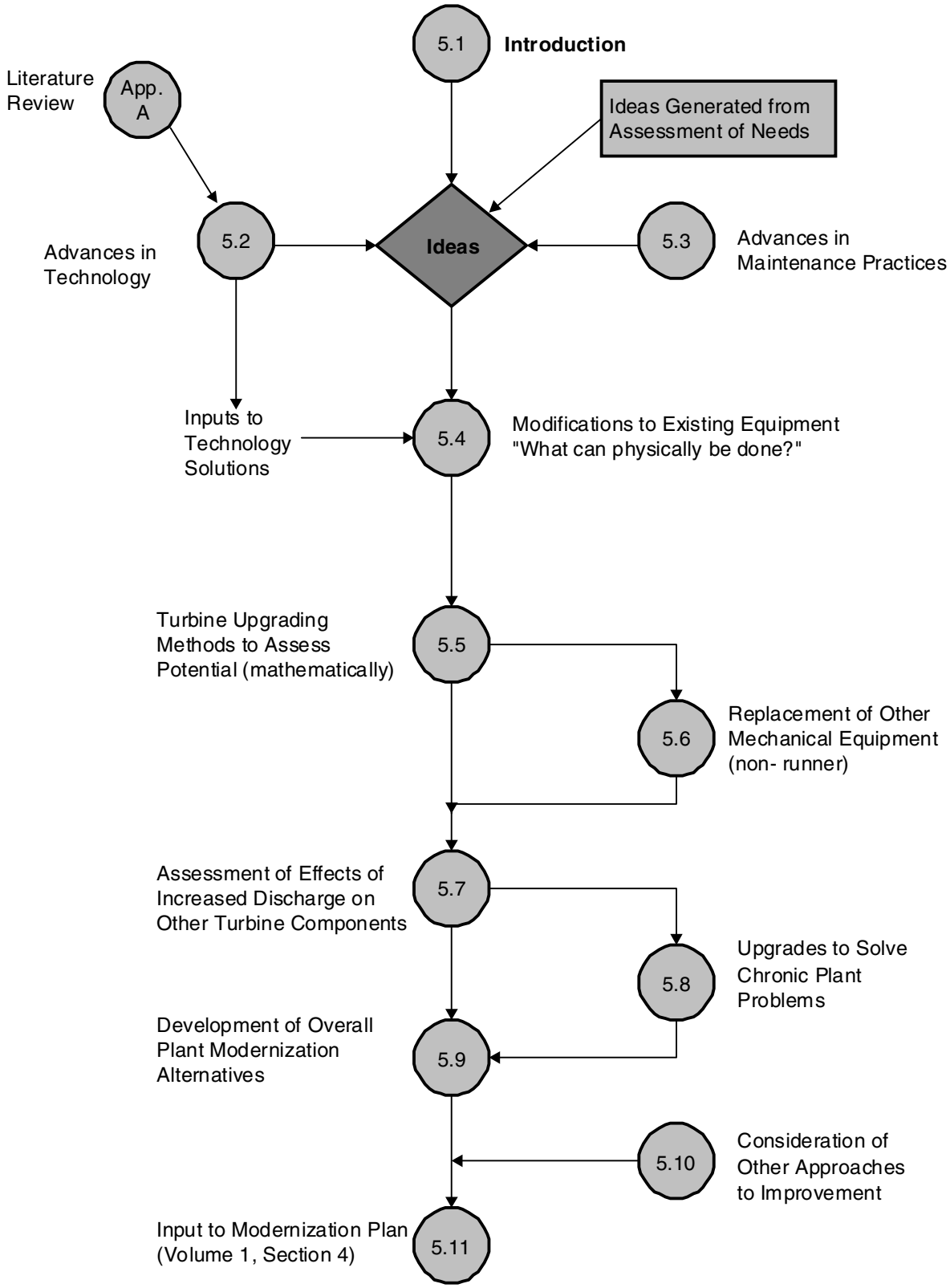

Figure 5-1
Potential for Improvements Process

Section 5 discusses modernization opportunities specifically for hydromechanical equipment. The information provided should assist with both the identification of opportunities and the assessment of the modernization alternatives. Table 5-2 is a summary of the areas of opportunity and activities to achieve these opportunities.

The pro forma "Equipment Modernization Opportunities" worksheet (Table 5-1), sometimes referred to as the "site worksheet", may be used for recording modernization opportunities during the condition assessment process outlined in Section 4, Volume 2. All opportunities identified should be included on the worksheets and then included in Tables 4-3 "Data Analysis for Hydro Plant" and 4-4 "Data Analysis and Inspection Results for Equipment and Structures" of Section 4, Volume 1. Alternatively, the data can be entered directly into these tables.

To assist in following the process, a depiction of Table 5-1 is provided at the start of each sub-section of Section 5. The highlighted portion indicates the part covered by the text included in the sub-section.

At the initial stage of assessment (i.e. in Section 4, Volume 2), potential opportunities are identified but not quantitatively evaluated. This will be done when all opportunities from across the plant have been collected in Table 4-6 of Volume 1. Table 5-1 is used at this stage to ensure that all possible activities are at least identified for consideration and none is deleted from the list too early in the process based only on an impression that the project would be uneconomic. Completing each worksheet, however, should trigger thoughts on the magnitude of the modernization opportunity as well as its impact on plant products (such as the ability to provide peaking power and load following capability) and the inter-relationship between modernizaton activities proposed for different equipment items.

The assessment of the relevancy and appropriateness made during the formulation of Table 4-6 of Volume 1 is not intended to be a thorough analysis, merely a "sensitivity" test. A thorough analysis will be conducted during the feasibility stage in Section 7, Volume 1 (with information from Section 7 of this Volume) if the identified opportunity is included in the selected LEM Plan taken forward for further consideration.

Table 5-1
Site Worksheet for Equipment Modernization Opportunities

Plant: _____
Equipment Name: _____
Unit No.: _____
Asset No.: _____
Prepared by: _____ **Date:**_____

Modernization Opportunities (Section 5.2, 5.3, 5.4, 5.5 & 5.6)	**Benefits of Modernization** (Sections 5.2, 5.5, 5.6, 5.7 and 5.8)
	Equipment:
Further Studies Required (Section 7)	
	Overall Plant:
Impacts of Modernization on Other Equipment (Section 5.7)	**Other Equipment that Limits Modernization** (Sections 5.4, 5.7 and 5.9)
Timing & Costs of Modernization (Section 4.9 and Section 6.0)	**Risk Evaluation of Modernization** (Section 4.6)
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

Table 5-2
Areas of Opportunity for Hydromechanical Equipment

Areas of Opportunity	Activities to Achieve Opportunities
1. Output (a) Increase plant capacity (for the plant, this can mean an increase in firm, high load hours and low load hour capacity) (b) Increase plant energy (head, flow, efficiency)	Activities or measures to increase unit efficiency/output: • new/improved runner design • increase vent opening • improve hydraulic design of static components using CFD design techniques • smoothing hydraulic surfaces • reprofile runner blades • reduce runner seal clearances • increase wicket gate opening via an increase in servomotor stroke • modify draft tube • increase the number of injectors (Pelton) • enlarge injectors (nozzle assemblies on Peltons) • optimize manifold, runner pit and venting sizing (Pelton)
2. Dependability (a) Age/equipment condition - identified equipment needs suggest areas of opportunity (b) Address operational improvements required (c) Address chronic equipment/plant problems (d) Increase plant/equipment reliability	Activities or measures to improve condition, operation and reliability: • draft tube modifications • upgrade to digital governor • add a tailwater depression system for Pelton units to allow operation during high tailwater or run-off conditions • upgrade TIV valve, operator and control system to reduce losses and increase reliability Implement measures to solve or mitigate chronic plant problems such as: • excessive cavitation/erosion • excessive vibration levels and pressure pulsations • chronic runner cracking
3. Sustainability Reduce environmental risks; improve environmental compliance	• development of "fish friendly" turbines • use electric servomotors or high pressure hydraulic systems to reduce volume of stored oil • use water-lubricated guide bearings • use self-lubricating wicket gate bushings
4. Flexibility Improve flexible operation for the plant as a whole (e.g. load factoring, swing, automated generation control [AGC])	• Implement a digital governor • Add tailwater depression system for Pelton units to allow operation during high tailwater or run-off conditions

Example of Completed "Equipment Modernization Opportunities" Worksheet

The following table (Table 5-3) is an example of a completed "Equipment Modernization Opportunities" worksheet for turbine wicket gate servomotors. It was developed using the following:

1. Section 4 and Appendix B of Volume 1 for identification of opportunities.

2. The condition assessment process of Section 4, Volume 2 for identification of opportunities.

3. Section 5, Volume 2, to further identify and assess the opportunities from a technical basis.

Section 4, Volume 1 clearly lays out the process for identifying needs and opportunities of equipment and defining them sufficiently for the LEM Plan. The flow of information between the process volume (Volume 1) and the technical volumes (Volumes 2-7), to support the development of the LEM Plan, can be complex. Figure 5-2 shows the flow of information in the process of identifying and defining "modernization opportunities" for the plant's hydromechanical equipment.

Table 5-3
SAMPLE Equipment Modernization Opportunities

Plant: Plant #1
Equipment Name: Wicket Gate Servomotors
Unit No.: 2
Asset No.: 1.1.1.3
Prepared by: I.M. Engineer **Date:** January 31, 2000

Modernization Opportunities (Section 5.2, 5.3, 5.4, 5.5 & 5.6)	**Benefits of Modernization** (Sections 5.2, 5. 5, 6, 5.7 and 5.8)
• Use of electric servomotors • Increase servomotor stroke	Equipment: • Increase in unit capacity • For electric servomotors, no hydraulic oil storage, easy maintenance and relative compactness
	Overall Plant: • Increase in plant capacity • Increase in plant energy • Increase in environmental compliance or decrease in plant environmental risk for electric servomotor option
Further Studies Equipment (Section 7)	
• Impact of increased unit discharge needs to be investigated for all plant equipment, including the intake equipment	
Impacts of Modernization on Other Equipment (Section 5.7)	**Other Equipment that Limits Modernization** (Sections 5.4 & 5.7)
• The need for fast emergency shutdown of unit limits application of electric servomotor technology • Runaway speed changes • Self-closing tendency and maximum torque requirements of wicket gates are affected	• Turbine blade outlet (vent) opening (limits maximum flow) to be investigated
Timing & Costs of Modernization (Section 4.9 and Section 6.0)	**Risk Evaluation of Modernization** (Section 4.6)
• Same time that wicket gate bushings are being replaced. Approximate cost, $100K	• Risk cost of oil spill reduced by $100K if electric servomotors used.
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	
• Increase servomotor stroke to increase wicket gate opening and therefore the unit capacity.	

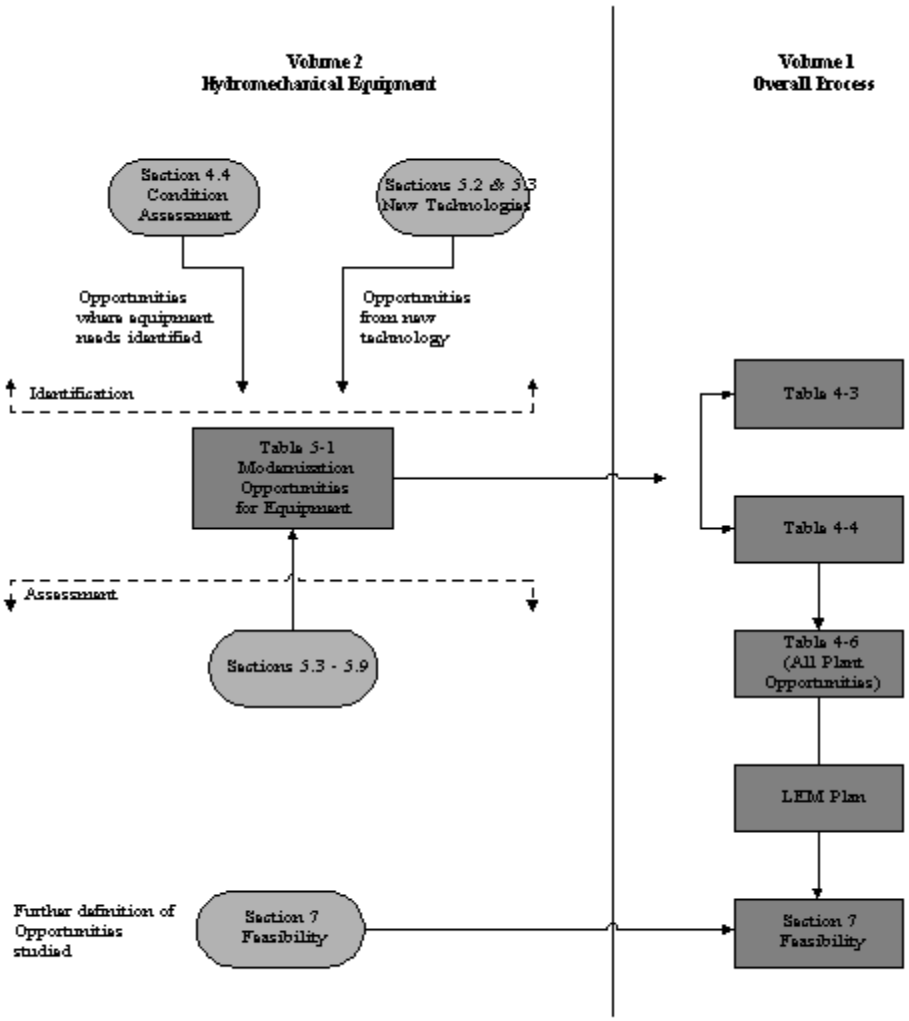

Figure 5-2
Flow of Information for Identifying and Assessing Modernization Opportunities for Hydromechanical Equipment

5.2 State of the Art

Modernization Opportunities (Step 4-5, Volume 1)	**Benefits of Modernization (Step 4-5, Volume 1)**
Further Studies Required	
Impacts of Modernization on Other Equipment	Other Equipment that Limits Modernization
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

5.2.1 Introduction

Table 5-4 “Summary of Advances in Technology for Hydromechanical Equipment" provides a quick reference for the modernization opportunities discussed in this Section. Appendix A contains a bibliography which provides references for further reading on equipment modernization topics.

There have been many developments in the technology associated with the hydroelectric industry. The drivers for the use of new technologies for modernization are:

- the main driver is the fierce competition amongst suppliers for a share of the market.
- more efficient, more reliable and hence more profitable equipment.
- environmental lobby for more environmentally friendly turbine equipment.
- many plants reaching the end of their economic lives and requiring decisions regarding their future.
- spin-offs from development of new plants i.e. technology developments originate on new turbines but later are applied to existing ones.

The opportunities presented by the use of newer technology are that of improved profitability, reliability and environmental performance. They can be achieved through:

- reducing the effects of the power plant on the environment
- increasing output and efficiency of equipment and hence the existing plant
- reducing operating and maintenance costs

Table 5-4
Summary of Advances in Technology for Hydromechanical Equipment

EQUIPMENT	ADVANCES IN TECHNOLOGY
Turbine	• Use of Computational Fluid Dynamics (CFD) for improved design of static hydraulic components • Upgraded/Improved with new runner design (CFD studies) i.e. better efficiency and/or more capacity • Condition monitoring - on-line assessment of condition (vibration, temperatures, etc.) • "Smoothing" of hydraulic surfaces - water passage improvements (stay vanes, spiral case, wicket gates, draft tubes) • Development of "fish-friendly" turbines • Advanced complete turbine designs
Runner	• Numerical design methods (CFD & Finite Element Analysis (FEA)) for improved performance (efficiency, output, cavitation) • Reprofiling blades using CFD techniques • Advanced complete turbine designs • Improved materials (specialty stainless steels and coatings) • Improved manufacturing techniques (NC machining) • Improved repair techniques (thermal spraying, etc.) • Improved testing techniques and accuracies (efficiency, flow measurement) • Conversion to water control for hub of Kaplan (blade operating mechanism)
Wicket Gates and Stay Ring and Vanes	• Increased efficiency through design improvement analyzed by numerical design methods (CFD) • Self-lubricated wicket gate bushings
Turbine Shaft Seal	• New seal designs with reduced air leakage in synchronous condense mode • Development of fibre resin type sealing elements • Improved seal designs
Pelton Nozzle Assemblies	• New nozzle/needle design with lower losses.
Turbine Guide Bearings	• Water-lubricated guide bearings on smaller units • PTFE bearings • Tighten bearing (reduce clearances) to allow tighter fitting runner seals (reduces losses, increases unit efficiency)
Governor	• Digital electronic systems for speed sensing and control and complete plant control (all system parameters) • High pressure hydraulics
Turbine Inlet Valve	• New design with improved flow dynamics and lower head losses due to CFD design techniques • Improved designs for electronic or hydraulic operating systems and emergency closure

In general, the use and development of computer-based technology has been a catalyst for enabling many of the developments outlined below.

The information which follows is current but, over time, will become dated. The user is encouraged to check for developments since the publication of this document in technical journals and conference proceedings and with manufacturers and suppliers.

5.2.2 Turbine Runners

Improvements in turbine runner technology have been driven by:

- The general requirement for increased power output, improved efficiency and less cavitation.
- The requirement to operate with greater flexibility to suit market needs by having equipment with higher efficiencies over a wider load range and eliminating "rough load zones", where operation was not previously possible.
- The search for increased availability and lower maintenance costs by reducing repair requirements due to cavitation, cracking and sediment abrasion.
- The requirement for enhanced environmental performance by improving fish survival rates, allowing small flows to be handled efficiently for riparian flow issues, increasing dissolved oxygen levels and maintaining acceptable water quality standards by using more environmentally-friendly lubricants.

This has been achieved by improvements in:

- Design methods
  - Computer analysis using Computational Fluid Dynamics (CFD)
  - (Physical) modelling techniques
  - Analytical techniques (power studies)
- Materials (stronger and corrosion/erosion/cavitation resistant)
- Manufacturing techniques
- Repair techniques
- Testing techniques (for example, flow measurement for efficiency testing)
- Operational techniques (for example, water management systems)

These improvements in runner technology have ensured that with proper considerations, the replacement of an old runner can generally result in delivery of greater power output at improved efficiencies. Very large capacity improvements are possible[1] along with efficiency improvements of 5 to 15%. The industry benchmarking survey conducted in conjunction with

[1] Zaikoff, D.W., *"Hydro Quebec's Comprehensive Approach to Analyzing Power Plants for Upgrading"*. Uprating and Refurbishing Hydropower Plants V. Conference Proceedings. Not Published.

the HydroVision '98 conference in Reno Nevada, provides some statistics on capacity and efficiency upgrades undertaken by plant owners.

Design Methods

Numerical methods, using advanced computing techniques have allowed improvements in the design of runners and associated static components. Computational Fluid Dynamics (CFD) has facilitated detailed examination of the characteristics of fluid flow and optimization of runner design. CFD has improved dramatically over the last few years and in some projects it is used in place of physical model testing, e.g. the investment required for physical model testing is often not economically justified for units of less than 50 MW capacity unless multiple turbines are involved. Where physical model testing is used, CFD enables runners to be optimized prior to any model testing and thus refines the model testing process.

CFD can assist in providing a design/prototype that will:

- Reduce swirl.
- Reduce the length of the hydraulic flow path in order to reduce skin friction.
- Reduce friction losses by optimizing the number of blades.
- Provide a smoother pressure change through the turbine.
- Optimize the design for minimum cavitation.
- Enhance fish survival.

The redesign of static components such as wicket gates, stay vanes, spiral case, etc., of the turbine is often carried out in conjunction with runner replacement to maximize efficiency gains from the modernization process. CFD techniques have proved to be extremely useful in this process.

CFD analysis of the draft tube is becoming more common and the importance of matching the runner design to the draft tube has become evident.

Other techniques such as Finite Element Analysis (FEA) for stress analysis and Fracture Mechanics for materials optimization have also contributed to the development of improved runners.

One turbine manufacturer has done some preliminary testing on the performance of reversible pump-turbines with splitter blades. A runner with splitter blades was developed for a high head, single stage, reversible pump-turbine. Some improvements were noted in efficiency, performance, the extent of the operating range and pressure fluctuations.

One turbine manufacturer has proposed a "hooped runner" design in which the buckets are supported within two circumferential hoops which have a spacing slightly greater than the jet diameter. The hoops are integral with the runner hub, and the forces on the buckets are

transmitted to the hub through the discs rather than through the root area of the bucket. Many problems associated with fatigue loading in the root area of the bucket are reduced.

Improvements implemented using new design techniques and driven by environmental issues include:[2]

- Enhanced fish passage survival rates
- Improved dissolved oxygen levels in water that has passed through the turbine
- Higher efficiencies or better control at minimum fish flows
- Reduced oil and grease pollution

As a result of work by many parties, advanced turbine designs, such as the e-"fish"-ient ™ Kaplan design developed under a Department of Energy (DOE) program, have appeared. The enhanced Kaplan turbine concept includes:[3]

- High efficiency over a wide operating range with reduced cavitation potential.
- A gapless design for hub, discharge ring and blades for enhanced fish passage survival.
- A non-overhanging design for wicket gates along with the use of environmentally friendly hydraulic fluid and lubricants.
- Greaseless wicket gate bushings.
- Smooth surface finishes and improved hydrodynamic design for stay vanes, wicket gates and draft tubes.

An environmentally enhanced Francis turbine concept has also been developed under the DOE program. Design features include: [4]

- A low turbulence, high efficiency, low cavitation design and a reduced number of blades compared to traditional designs.
- A non-overhanging design for wicket gates.
- Use of environmentally friendly hydraulic fluids for the governor.
- Greaseless wicket gate bushings.
- Upgraded surface finishes for stay vanes, wicket gates and draft tube.
- Adjustable speed generator for wide head range plants.

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[2] Fisher, R.K., Marik, P.A., Mathur, D., Sotiropoulos, F., Franke, G., *"Innovative Environmental Technologies Brighten Hydro's Future"*, presented at Hydrovision '98, Reno, Nevada, August 1998.

[3] Fisher, R.K., Marik, P.A., Mathur, D., Sotiropoulos, F., Franke, G., *"Innovative Environmental Technologies Brighten Hydro's Future"*, presented at Hydrovision '98, Reno, Nevada, August 1998.

[4] Fisher, R.K., Marik, P.A., Mathur, D., Sotiropoulos, F., Franke, G., *"Innovative Environmental Technologies Brighten Hydro's Future"*, presented at Hydrovision '98, Reno, Nevada, August 1998.

- An advanced control system to operate the unit in "fish friendly modes".

Materials

The drivers of material property improvements have been:

- Cavitation, corrosion and abrasion resistance to improve component life and reduce outage rates.
- Increased strength to reduce runner weight and improve efficiency.
- Machinability which leads to smaller design/manufacture tolerances and the ability to fabricate more complex shapes for optimal equipment design.
- Repairability (generally weldability) to reduce outage time for weld repairs and associated heat treatment.

The evolution of materials has seen cast carbon steel replaced with cast and plate stainless steels, both martensitic and austenitic, which have greater cavitation resistance and corrosion resistance. Specialty stainless steel weld materials such as Nitronic 60 and cobalt based materials similar to Stellite have been used in areas where stainless steel base materials suffer from cavitation damage. These materials provide cavitation resistance about three times that of stainless steel. The use of non-fused polymer type materials has also been investigated; however results have been mixed.[5]

There have also been significant advances in coatings to reduce erosion. Softer/smoother materials have been developed for lower head, relatively low velocity applications. For high head Francis and Pelton turbines thermal sprayed tungsten cobalt coatings have been used with some success.

Manufacturing Techniques

The drivers of manufacturing improvements have been:

- Use of fabricated runners - most of the new Francis runners, and to an increasing extent Pelton runners, are manufactured by welding together of individual premachined components.
- The requirement to manufacture more intricate blade shapes.
- The requirement to consistently produce a quality item.
- The availability of improved materials which require new manufacturing techniques.
- The requirement to ensure homology between the model and the prototype runner.

[5] Moss, W.O., Morton, R., *"The Successful Solution to Cavitation Problems at Dinorwig Power Plant with the Aid of Polymeric Coatings"*, Uprating and Refurbishing Hydro Powerplants V Conference Proceedings, Vol. 3, 1995.

Major advances in the control, versatility and precision of machine tools have resulted in considerably more accurate components. In particular, computerized controls on multi-axis machining equipment have enabled the accurate machining of complex contours such as those on turbine runner blades. The resulting improvements in performance are:

- greater efficiency
- less hydraulic imbalance and less cavitation due to manufacturing errors
- increased power output as a result of greater efficiency and less cavitation

The same computer file developed for the hydraulic design is used for numerically controlled (NC) machining of both the model runner and the prototype runner. This enables close homology between the computerized design, the model and the finished product which provides for more rapid design development and means that the model performance will more accurately predict the prototype performance.

Improvements in casting techniques and associated controls have resulted in castings with increased strength and toughness and with more uniform properties. In the case of turbine runners, this means that blade thicknesses may be reduced to improve runner performance.

For Pelton runners, in addition to improvements in casting techniques, new manufacturing methods have been developed which address the high (fatigue) stress area at the root of the bucket. One manufacturer has a design where the runner hub and inner part of the bucket (root area) are a one piece forging. The outer portions of the buckets are constructed by welding. Smaller runners have been machined from a single block of stainless steel using NC methods.

New measurement techniques for verifying runner homology include the use of theodolities for improved accuracy.

Repair Techniques

Repair techniques for runners and associated static elements have advanced with the advent of techniques such as the thermal spraying of metals enabling thin layers of metals to be applied to parent surfaces and the new surface to then be machined. Weld materials and techniques have also advanced as previously mentioned but require heat treatment and stress relief to be successful. Water jet cutting is also used during repairs.

The benefits of improved repair techniques have been:

- Reduced number of outages
- Reduced outage durations
- Reduced outage costs

New technology is being used for cavitation damage repair. Some utilities are looking at using robotic devices for in-situ cavitation repairs.

Testing Techniques

The driver for testing improvements for turbine runners has been the requirement for more detailed and accurate information regarding the performance of both hydraulic models and prototype units.

Hydraulic models now provide information which more closely predicts the prototype performance by:

- Improved measuring and computing techniques.
- Improved manufacturing techniques which allow the reproduction of the model runner to a full size runner (computer aided design (CAD) and manufacture (CAM)).

Performance tests of prototype units have also gained in accuracy due to the introduction of more advanced measuring tools which assist in the measurement of flows, pressures, temperatures, etc.

New flow measurement devices for efficiency testing are available. One such device is the acoustic scintillation flow meter which measures the flow in a turbulent medium by transmitting sound signals across the channel or passage in which the flow is to be measured.

When reviewing different test methods or devices, it is important to ensure that they are approved in the test code governing the turbine efficiency test if the test measurement obtained is required to be in compliance with the test code.

See Section 7 for information on the range of testing methods available.

Operational Techniques

There is ongoing development of hydro management systems to control and optimize unit, plant and water system operations. These "knowledge management systems" are being offered by both turbine suppliers and utilities who can incorporate process knowledge and operations and maintenance experience into their software packages. These knowledge management systems aim to:

- increase efficiency and production
- reduce maintenance costs
- improve environmental performance

Knowledge management systems such as WaterView developed by TVA and Voith Hydro, gather data provided from a data acquisition system or SCADA, and use the data to provide advisory information to system operators and control systems.

Functionality can include:

- real-time performance tests on units, comparing an existing operating point to the latest performance curve

- optimization of unit scheduling to meet river or system management criteria such as fish or irrigation flow requirements, water treaty obligations, system load demands, etc.
- environmental monitoring

Turbine and protection and control equipment suppliers should be contacted for information on the latest technology available.

5.2.3 Wicket Gates and Wicket Gate Operating System

Wicket Gates

In recent years, the use of CFD techniques has increased the opportunities for efficiency gains by replacing the wicket gates and modifying stay vanes. To achieve these gains, wicket gates and stay vanes are modified:

- to be more hydrodynamic
- to have a better angle of approach
- to suit 'actual' head conditions

For wicket gates, the use of self-lubricated (greaseless) bushings is becoming more common. The drivers for the use of self lubricated bushing are:

- Improved environmental performance
- Decreased maintenance costs

In the past, a possible source of hydrocarbon contamination has been grease leakage from wicket gate bushings. The self lubricating bushing is now used to replace the classical bronze wicket gate bushing to improve environmental performance.[6] The elimination of high viciosity grease can mean reduced bushing clearances. This may improve governor control and reduce intergate wicket gate leakage.

Self lubricating wicket gate bushings can be cast brass, cast bronze or a metallic matrix with either of the following:[7]

- high density polyethylene or elastomerics such as polytetrafluoroethylene (PTFE) fluorocarbon
- graphite or other embedded/impregnated solid lubricant

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[6] American Society of Mechanical Engineers, Hydropower Technical Committee, HCI Publications Inc., Kansas City, MO 1996, *"The Guide to Hydropower Mechanical Design"*.

[7] "New Lubricating Material for Hydraulic Turbine Generators", Canadian Electric Association, Montreal, Quebec, November 1994, CEA No. 9112 G 830.

PTFE bushings are water-lubricated, synthetic, low friction materials. They may be homogenous or supported by stainless steel or bronze backings. The PTFE bushings have a lower coefficient of friction than bronze bushings and do not require a lubrication medium other than water. PTFE bushings must be used with wicket gate trunnions either constructed of stainless steel or overlaid with stainless steel to prevent corrosion of the wicket gate trunnions. Installations that use self-lubricated bushings need to consider possible expansion from thermal changes and water absorption. PTFE bushings are prone to wear when the water has a high particle content, in which case bearing end seals are recommended. PTFE bushings also can be brittle and care during installation is required to prevent cracking during installation. Similarly, the trunnions should be provided with chamfers or relief areas to facilitate installation.

Graphite bronze bushings contain circular inserts of carbon material incorporated in the bronze bushing. The carbon material lubricates the wicket gate stems during operation of the wicket gate. Care in handling, storage and installation is required to prevent damage such as cracking or flaking of the graphite material.

Graphite-impregnated bushings are bushings in which graphite particles are put in the molton bronze during the manufacturing process. The graphite lubricates the mating wicket gate trunnion as the bronze bushing wears.[8]

Some problems have been experienced with self-lubricating bushings on large units in the past. Care must be taken when selecting a self-lubricating bushing for a particular application.

Self lubricating bushings are usually more expensive than the traditional bronze bushing, particularly on larger units, but have lower maintenance costs because of the elimination of the grease lubricating system.

5.2.4 Pelton Nozzle Assemblies

New nozzle/needle designs are available to improve jet performance and unit efficiency. Some older Pelton turbines have nozzle entrance sections which provide a gradually reducing cross-sectional area to create an accelerating flow velocity to the nozzle tip. This results in higher losses. Turbine manufacturers should be contacted for information on the latest designs available.

5.2.5 Other Turbine Hydraulic Components

Stay ring and vane modification is normally considered in conjunction with runner replacement, through the use of CFD techniques, to add further efficiency gains. To achieve these gains, the stay ring and vanes are modified:

- to be more hydrodynamic

[8] American Society of Mechanical Mechanical Engineers, Hydropower Technical Committee, HCI Publications Inc., Kansas City, MO 1996, *"The Guide to Hydropower Mechanical Design"*.

- to have a better angle of approach
- to "suit" actual head conditions

Reshaping the stay ring and vanes to the design recommended by CFD could involve the addition of plates to the stay ring shrouds (deck plates) and modifications of the existing vanes by addition of or removal of metal from the leading and trailing edges of the vanes. Where metal removal is required, the modifications can be carried out at site with flame cutting, machining, water jet cutting and/or grinding.

Another development in the area of stay vanes is the use of polymers for the repair of pump mode cavitation damage on pump-turbines. [9]

5.2.6 Shaft, Shaft Seal and Turbine Guide Bearings

Shaft Seal

Shaft seal designs with fibre resin type sealing elements have been developed over the past 20 years. This seal design requires less maintenance and in many cases does not require a separate shaft seal water supply. This type of seal can replace the traditional stuffing box type seals. For turbines which must operate part of the time spinning in air, the new seal designs have reduced air leakage, reducing the load on the turbine or pump-turbine compressed air blow down system.

Water-Lubricated Turbine Guide Bearings

Smaller turbines are now able to use water-lubricated turbine guide bearings, in lieu of oil lubrication, to eliminate another source of oil/grease contamination.[10] Depending on the size of the unit, the costs can be comparable to or even lower than conventional oil lubricated guide bearings. Most water-lubricated bearings today are a plastic, high density polyethylene or elastomeric type material such as PTFE. Traditional water-lubricated bearings are made of wood (lignum vita) but this material is sometimes hard to find.

5.2.7 Governing System

Modern digital governors can perform many additional functions not previously provided by mechanical governors and some not provided by analogue governors. They can control any

[9] Moss, W.O., Morton. R., *"The Successful Solution to Cavitation Problems at Dinorwig Power Plant with the aid of Polymeric Coatings",* Uprating and Refurbishing Hydro Powerplants V Conference Proceedings, Vol. 3, 1995.

[10] ASME Hydro Power Technical Committee, *The Guide to Hydropower Mechanical Design,* HCI Publications, Kansas City, MO 1996

system parameter that can be sensed by a transducer, switch or contact.[11] Examples of the functions they can supply include:

- Speed and power control.
- Generator control - can include voltage and VAR control.
- Level control - for head or tailwater control.
- Flow control - for minimum flows
- Turbine creep detection.
- Control sequencing - can expand unit sequencing capabilities such as sequencing of multiple units or unit start/stop based on time to control ponding, irrigation, or scenic water flow requirements.
- Unit remote control - can remotely start, stop and change set points and governor parameters and send warnings and log data by communications link.
- Loading Optimization Schemes - software can be written to maintain unit operation in the higher efficiency regions of the unit operating range and to avoid rough zones of operation. Turbine data can be programmed into the governor to make automatic adjustments to avoid operation under high cavitation conditions.
- Dual-Regulated Turbine Optimization - For Kaplan and Pelton turbines, there are optimum regulation requirements for the secondary control servo. For Kaplan turbines, gross head and gate positions are used as inputs to determine optimum blade position. For Pelton turbines, increased efficiency can be gained with needle sequencing. For example, at a half-rated capacity, a six-needle machine has a higher efficiency with four needles in service than with six.[12]

The main advantage of a digital governor is its versatility and its ease of upgrading and interfacing with other computers and control systems. However, they may be more difficult to maintain by local staff due to their complexity.

5.2.8 Turbine Inlet Valve (TIV)

New valve designs, developed using CFD and other numerical design techniques, have much lower head losses than older designs. TIV actuators typically have accumulators or a counterweight for reliable closure with no power. Modern actuators utilize high pressure hydraulic systems which require less space. Where accumulators are provided, modern designs utilize nitrogen charged piston or bladder accumulators rather than an air-over-oil accumulator tank which requires a reliable compressed air system. Controls are usually by computer or PLC.

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[11] ASME Hydro Power Technical Committee, *The Guide to Hydropower Mechanical Design,* HCI Publications, Kansas City, MO, 1996

[12] ASME Hydro Power Technical Committee, *The Guide to Hydropower Mechanical Design,* HCI Publications, Kansas City, MO, 1996

5.3 Equipment Maintenance - Changes in Approach/Improvements

Modernization Opportunities (Step 4-5, Volume 1)	Benefits of Modernization (Step 4-5, Volume 1)
Further Studies Required	
Impacts of Modernization on Other Equipment	Other Equipment that Limits Modernization
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

These guidelines are not intended to discuss maintenance practices and techniques. At times during the use of these guidelines, however, it is only natural that maintenance will be discussed when assessing a plant's performance and outlook for the future. Accordingly, this section will only comment on some of the advances in high level equipment maintenance approaches.

5.3.1 Predictive Maintenance

The drivers for the use of predictive maintenance and condition monitoring have been improved profitability. This is being achieved by:

- Increased reliability
- Increased intervals between outages
- Decreased outage durations

Predictive maintenance involves the collection and interpretation of operational data to predict maintenance requirements.

The aim of using predictive maintenance is to attempt to extend maintenance intervals beyond the existing, time-based preventative maintenance periods. Predictive maintenance also seeks to identify and rectify problems before they become catastrophic which may not have been possible by relying on preventative maintenance techniques. Ultimately predictive maintenance is a maintenance approach designed to:

a. reduce risk of equipment failure

b. reduce overall equipment costs

c. improve commercial availability

5.3.2 Machine Condition Monitoring (MCM)

Machine Condition Monitoring (MCM) is used to provide a more comprehensive predictive maintenance program. It collects performance data, either continuously or periodically, such as vibration, temperature, flow rates, power usage and oil quality. This data, at present, is

interpreted "off-line" to attempt to predict maintenance requirements. Many attempts are underway to use condition monitoring systems "on-line" which will continuously monitor parameters and provide "smart" alarms which are more predictive than the present alarms used which simply alert the operator that a set point has been reached which does not allow for outside parameters.

An example of the use of a "smart" system condition monitoring would be an alarm which alerts the operator to a problem with a turbine guide bearing temperature at half load which is not critical, in terms of maximum allowable bearing temperature, at that juncture, but which is an indicator of a problem occurring. By identifying the problem at an earlier point, there is the opportunity to investigate and perhaps fix the problem at a more convenient opportunity than later, when the problem is identified at full load and a forced outage is not desirable.

Four key benefits of applying MCM technology in generating stations have been identified. They are:

- Value of increased system capacity - The potential of hydroelectric MCM to enable planned "overloading" of generating units which are "monitored" to ensure minimal impact on equipment life and maintenance costs, could add to overall system peak capacity, thus avoiding the incremental cost of acquiring new generating capacity. Less reserve capacity would also be necessary for covering periods of planned and unscheduled outage if these outage are reduced.
- Energy value from utilizing present "spills" - Water is sometimes spilled when there is excess water behind a dam, or when generating units are out of service for maintenance or repairs. The potential for hydroelectric MCM to enable both planned overloading, and reduce maintenance and repair down-time, could permit more water to be run through generating units, thus providing an increased energy output.
- Value of reduced timely maintenance and repair outages - Presently, generating units are usually taken out of service on a time-scheduled (calendar-driven) maintenance program, or when a failure has occurred (machine trip or human detection). An effective hydroelectric MCM system, which enables "condition-driven" maintenance, has the potential to reduce maintenance costs by helping to ensure that maintenance work performed is necessary when undertaken, and ample warning is given to minimize system utilization problems.
- Value of life extension for aging equipment - The implementation of an effective MCM system would enable the informed deferral of equipment rebuilds, as compared to the present system of calendar-driven ("scheduled") equipment rebuilds.

In addition to these key benefits, other financially tangible and intangible benefits may include:

- improved generating unit operating efficiency,
- improved system efficiency,
- improved risk management on "run-of-the-river" plants,
- improved outage planning (system balancing and substitution),
- improved environmental monitoring,

- improved safety,
- reduced spare part inventories,
- and improved operational and maintenance skills.

A problem with implementing condition monitoring in a hydro plant situation is that the plant has very slow wear rates. Changes in performance, which provide the trends that condition monitoring relies upon, are very gradual, i.e. over many years, and trending of these parameters needs to take this into account.

5.3.3 Reliability Centered Maintenance (RCM)

History of RCM

RCM was first developed by the commercial aviation industry in the late 1960's. In order to establish the economic viability of the larger more complex wide-body jets, with increasing concerns over public safety, a different approach to maintenance was required. The approach taken was to preserve system function rather than equipment operation, the forms of traditional maintenance. RCM was accepted by the US Federal Aviation Administration and became an industry standard.

In the mid 1970's the US Department of Defense, under pressure to reduce operation and maintenance costs of their military aircraft without sacrificing reliability, adopted the same philosophy.

In the early 1980's, RCM pilot applications in the nuclear power industry revealed a reduction in the number of forced outages and an estimated 30 to 40% savings in maintenance costs. By the mid 1990's EPRI working with Transmission and Distribution Utilities was conducting pilots on applications in substations and software was taking the place of the manual spreadsheets for analysis and record keeping.

What Is It?

RCM can be described as "a structured method for developing an initial maintenance program or for optimizing an existing maintenance program to preserve critical system functions based on safety, operational and economic criteria".

RCM is a structured decision-making process that assembles the various proven maintenance standards including "time based preventative", "condition based" or "predictive" and "operate to failure" using a benefit optimization approach to establish a new maintenance strategy. The philosophy is to maintain critical systems; non critical or redundant systems may be allowed to fail.

RCM is comprised of the following basic steps:

1. select the functional system, ie turbine, governor etc.
2. define system boundaries, ie valves, switches etc.
3. identify critical system and component functions
4. perform a failure mode and effects analysis (FMEA)
5. select appropriate maintenance tasks at an optimized frequency
6. compare the maintenance tasks selected to current ones
7. group tasks and implement new maintenance program
8. implement a process where the program is reviewed as conditions change.

The heart of RCM is the Failure Mode and Effects Analysis (FMEA) which is used to study critical systems and determine how they can be best maintained to avoid component failures and improve overall reliability. This is accomplished by asking seven questions;

1. what is the function of the device?
2. how can it fail?
3. what is the cause of each failure?
4. what happens when a failure occurs?
5. why does the failure matter?
6. what can be done to prevent or predict each failure?
7. what can be done if a suitable proactive task is not available?

The process is powerful for the following reasons:

1. it is a structured, logical approach which creates a documented maintenance program
2. it identifies critical equipment that may not have been maintained to date
3. it incorporates all the different maintenance styles in an optimized format
4. it readily accepts the input of knowledgeable trades and technical people
5. it can be modified easily as equipment and process changes occur.

It is not intended to address design concerns although the process may identify as of yet unidentified, design related equipment issues. It also does not address inadequacies in training, work procedures (quality issues) or the occurrence of human error.

What Are The Benefits?

The results of a fully implemented RCM program typically yield:

1. increased confidence to meet regulatory requirements
2. increased unit availability
3. more efficient expenditures of maintenance dollars

In summary, the benefits of RCM are significant when fully implemented. The risks are that its implementation is under-resourced or that senior management does not give it the priority or focus it needs.

5.4 Modifications to Existing Equipment

Modernization Opportunities (Step 4-5, Volume 1)	**Benefits of Modernization (Step 4-5, Volume 1)**
Further Studies Required	
Impacts of Modernization on Other Equipment	**Other Equipment that Limits Modernization (Sep 4-5, Volume 1)**
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

Section 5.4 discusses the equipment modernization options that involve modifications to the existing mechanical equipment rather than replacement.

Sections 5.5 and 5.6 discuss replacement of the runner and other mechanical equipment respectively as modernization activities.

Any equipment modifications identified for the particular piece of equipment should be input into their Equipment Modernization Opportunities worksheet (Table 5-1) for future consideration as part of the LEM Plan.

Table 5-5 summarizes the possible equipment modifications.

5.4.1 Introduction

Turbine capacity is determined by component designs that limit water flow through the unit and/or the ability to withstand operating loads. Limitations on water flow are usually caused by dimensional limitations or cavitation limits, while the ability to transmit load is limited by the component dimension and by the allowable stress limits of the component material. In the

following section, the major design limits on equipment are discussed and possible modifications to increase efficiency and output are presented.

Table 5-5
Modernization through Modifications to Existing Hydromechanical Equipment

Section	Equipment	Modification
5.4.2	Runner (Francis)	• Increase blade outlet (vent) openings (smallest opening between adjacent blades) • Reprofiling of blades
	Runner (Kaplan)	• Change blade angle - ensure blade/wicket gate angle is optimized • Reprofiling of blades
	Runner (Pelton)	• New runner (change bucket size and design/shape)
5.4.3	Wicket Gates and Wicket Gate Operating Mechanism	• Increase servomotor stroke limits (wicket gate opening) by: – shorten pistons – modify wicket gate linkages – increase length of servomotor cylinders – machine servomotor heads to increase stroke • Replace oil-based gate operating system with electric servomotors.
5.4.4	Pelton Nozzle Assemblies and Deflectors	• Increase output by enlarging the needle and nozzle seats. • Modify size and stroke of the deflectors - only required if the jet diameter is changed.
5.4.5	Other Hydraulic Components	• Stay ring and vane modifications • "Smoothing" of hydraulic pathways to reduce losses. • Draft tube modifications • Add tailwater depression system for Pelton units to allow operation under high tailwater or run-off conditions. • Optimize distributor, nozzle assemblies, and air venting sizing on Peltons
5.4.6	Shaft	• Increase size of shaft to accommodate increased turbine output if shaft strength is limiting factor. • User higher strength material for shaft if shaft diameter is limiting factor for increased turbine output.
5.4.7	Governing System	• Change the way a digital governor controls flow (and keeps flow constant while the valves are opening and closing) by using the deflector. • Upgrade controls to improve speed regulation and responsiveness

Uprating the turbine capacity is the most common reason that turbine modernization is considered, and the uprating potential of the turbine is dependent on several considerations. Uprating or increasing turbine output is achieved by increasing the:

- head on the turbine
- flow through the unit
- efficiency of the unit

Turbine uprating by increased turbine output is discussed in Section 5.5. Increased head (by increased headwater elevations, decreased tailwater levels or decreased losses) can be accomplished by methods which are external to the turbine and these methods are discussed in Volume 6 of these Guidelines. Increasing the operating head on the turbine, however, changes the design conditions. Significant increases in head may warrant a turbine modernization evaluation. Also, a higher head may allow output beyond the capabilities of other mechanical equipment necessitating an evaluation of their uprating potential, as discussed in the following paragraphs.

The following discussion assumes that higher head or flow conditions exist. For a run-of-river plant, the spilling frequency screening criteria in Volume 1, Section 3 can provide a gross indication of any increased hydrologic potential. For peaking operation, the higher capacity may provide improved capacity credits because of the increased capability.

Turbine uprating can be approached in the following two ways:

- determine the operating capacity of an uprated turbine within the dimensions of the existing components; or
- determine the maximum turbine capacity which can be installed in the powerhouse bay width. (This methodology will not be studied in these Guidelines.)

Approaches to upgrading Pelton turbines through equipment modifications can include:

- changing the efficiency-load curve, possibly making it flatter at higher loads. Most vertical impulse units were originally configured with a peak efficiency at 65% of full load. Efficiency improvements of 0.5% to 4% are common.
- Improving the condition of runner and needle/seat assemblies which are reducing the unit's output and efficiency.
- Optimizing the angle between jets for two-jet turbines. Increasing the angle can greatly improve efficiency.

5.4.2 Runner

Increased turbine output can be achieved by increasing:

- turbine head,
- turbine efficiency, or
- turbine discharge,

as illustrated in Figure 5-3 which shows the hill curves for a turbine.

The hill curves plot efficiency as a function of discharge and head. Figure 5-3 also shows the operating range of flow and head and the limiting factors on the unit, such as cavitation, generator capacity, wicket gate opening and the occurrence of pressure surges at certain operating points.

For plants with water storage capability, rated head is selected to be equal to design head, i.e., the weighted average head or the value above and below which an equal amount of energy is produced. For run of river plants, "rated head" may be taken as the head at the best or peak efficiency point.

The turbine runner output limitations are the discharge diameter, vent openings for a Francis turbine, blade angle for a Kaplan turbine, bucket size for Peltons, cavitation, and runner stress. Figure 5-4 shows the basic dimensions of interest on Francis and Kaplan turbines

Limitations on Output

Flow through Francis turbines is limited by the smaller of either the area between the runner blades (vent opening) or the area between the wicket gates. Measurements of these areas can be used to determine if they limit output.

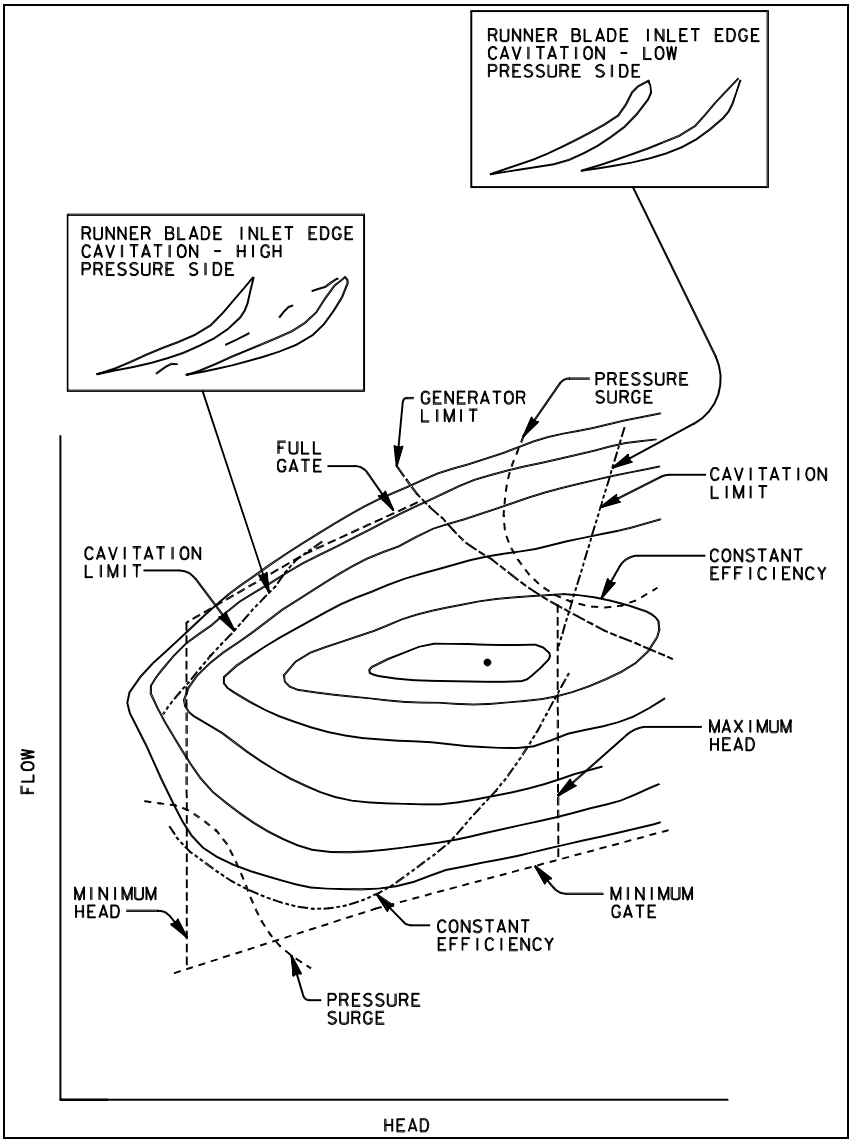

Figure Figure 5-3
Prototype Turbine Hill Curve

Efficiency as a function of head and flow typically are summarized on a hill curve, similar to the one shown in this figure. Operation is limited by pressure pulsations, potential cavitation damage, and maximum power.

The Guide to Hydropower Mechanical Design: ASME Hydro Power Technical Committee. Published by HCI Publications, Kansas City, MO, 1996. Web: www.hcipub.com. Used with permission.

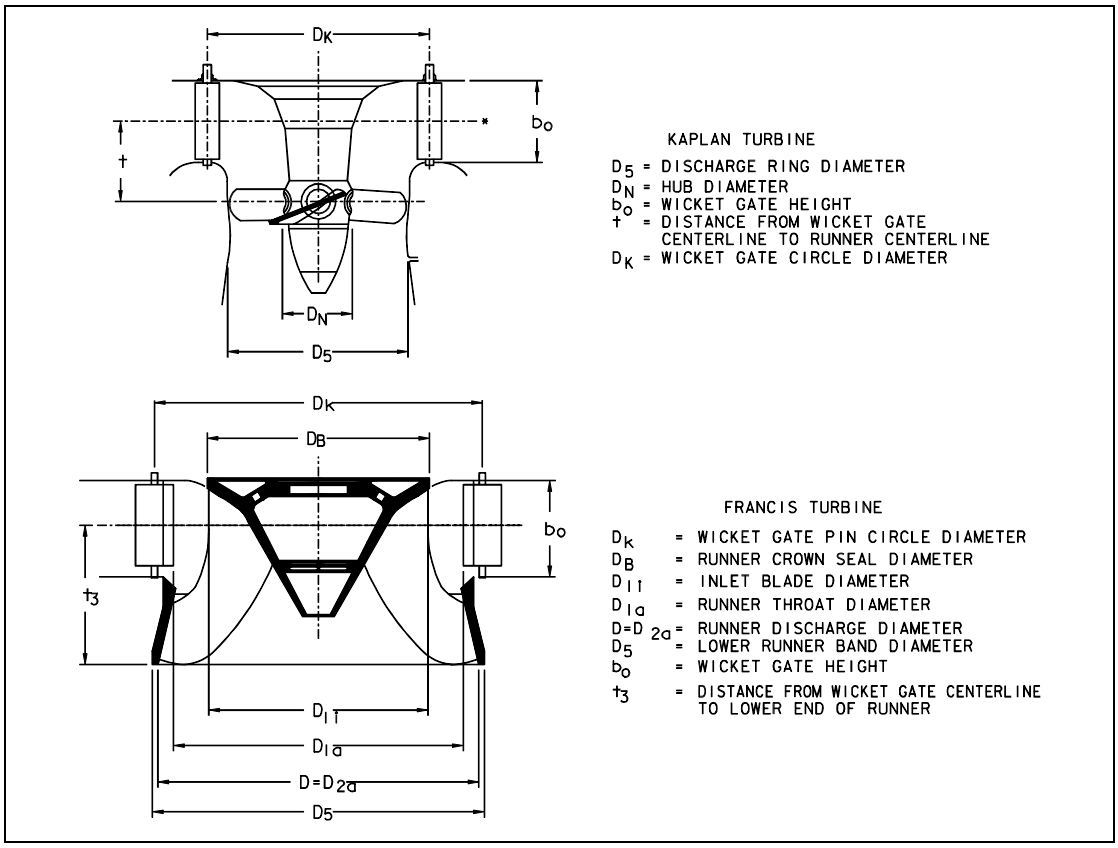
KAPLAN TURBINE
D5 = DISCHARGE RING DIAMETER
DN = HUB DIAMETER
bo = WICKET GATE HEIGHT
t = DISTANCE FROM WICKET GATE CENTERLINE TO RUNNER CENTERLINE
DK = WICKET GATE CIRCLE DIAMETER
FRANCIS TURBINE
DK = WICKET GATE PIN CIRCLE DIAMETER
DB = RUNNER CROWN SEAL DIAMETER
D11 = INLET BLADE DIAMETER
D1a = RUNNER THROAT DIAMETER
D=D2a = RUNNER DISCHARGE DIAMETER
D5 = LOWER RUNNER BAND DIAMETER
bo = WICKET GATE HEIGHT
t3 = DISTANCE FROM WICKET GATE CENTERLINE TO LOWER END OF RUNNER

Figure 5-4
Runner and Wicket Gate Dimensions

A unit output versus servomotor stroke curve can also provide a good indication of flow limitation. For example, the turbine output on Curve A in Figure 5-5 is likely to be limited by the turbine runner, since the maximum output is reached before the servomotor reaches its maximum stroke at 100%. Operation at higher gate openings does not provide additional output and may cause cavitation and vibration problems. Therefore, the maximum operating limit for the turbine having Curve A performance is at servomotor stroke corresponding to about 75%. Increased turbine output is possible by installing a new runner with a larger vent opening or increasing the vent on the existing runner, as shown by the dashed line in Curve A of Figure 5-5. Adjustments to the runner vent should be investigated by a specialist to determine the effects on performance at part load and runaway speed. The procedure is to reduce the runner blade length by trimming off the end of the runner blade to increase the vent area. The increased vent opening will shift the turbine performance curve in the direction of increased capacity. The increase of flow will be proportional to the increase in vent opening and depends on the shape of the blades.

In shifting turbine performance to obtain higher output, the overall turbine efficiency will decrease and the minimum output for operation will increase. Increasing output by increasing the runner vent opening will increase the risk of cavitation and should only be considered if the present runner is cavitation free.

Performing runner modifications on the prototype without model tests can be expensive, time-consuming, and may result in unexpected and unwanted performance changes. Increased runaway speeds due to a new or modified runner should be compared with and not exceed the generator design values.

As shown on the example in Figure 5-5, Curve B, unit output continues to increase up to the maximum servomotor stroke, and the slope of the curve indicates that additional output may be possible if the servomotor stroke were increased. In this case, output is limited by the servomotor stroke and increasing the servomotor stroke would likely increase output.

Figure 5-6 shows an example of a Francis turbine where runner output is limited because of cavitation damage, but has the potential for additional output. In this example, output is limited to Level A because of excessive cavitation above that level. In this case, runner vent opening and wicket gate opening do not limit output since the wicket gate opening can be increased to enhance power output. Increasing output to Level B may be possible by using a more cavitation-resistant material if the runner is carbon steel. This can be achieved by weld overlay of the cavitated area with E309 weld electrode or one of the newer alloy steels developed specifically for this purpose. This would reduce cavitation or, alternatively, a new stainless steel runner can be installed as discussed in Section 5.5.

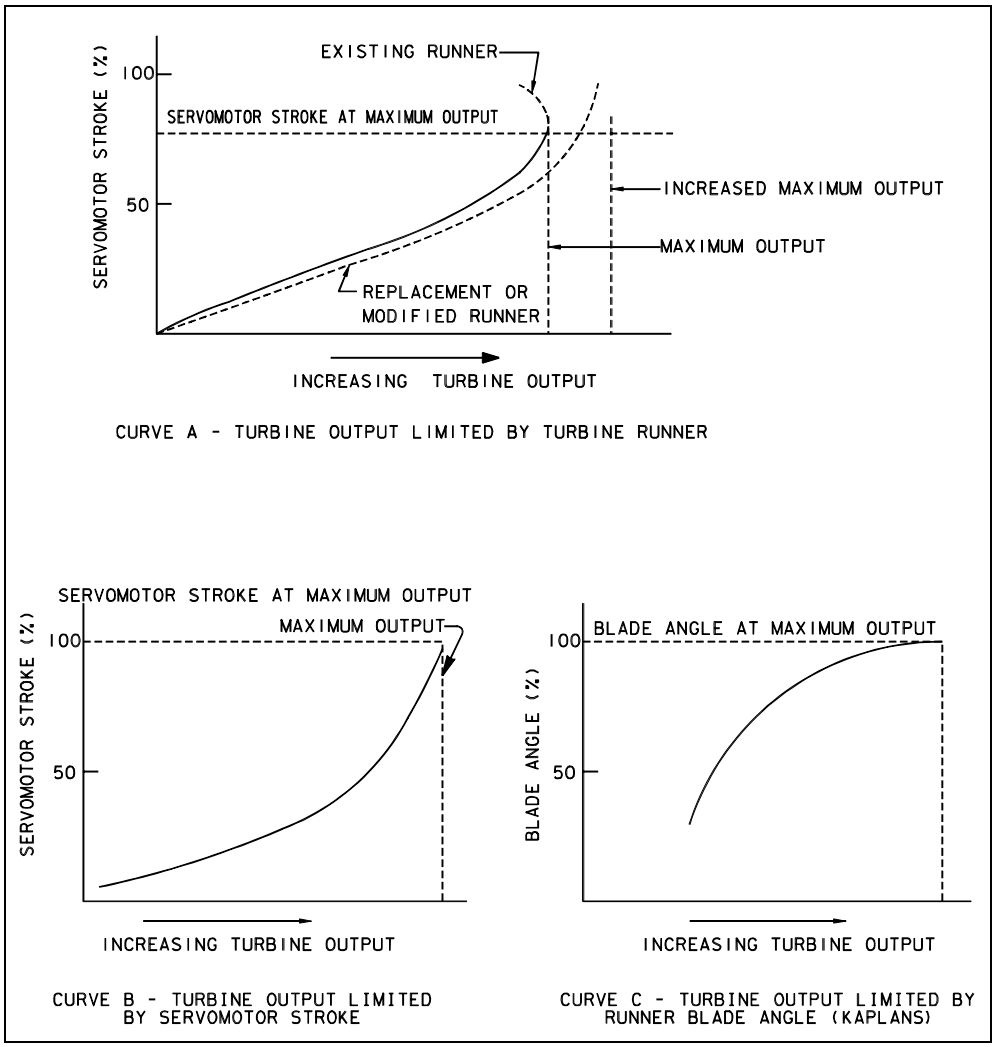

Figure 5-5
Causes of Turbine Output Limits

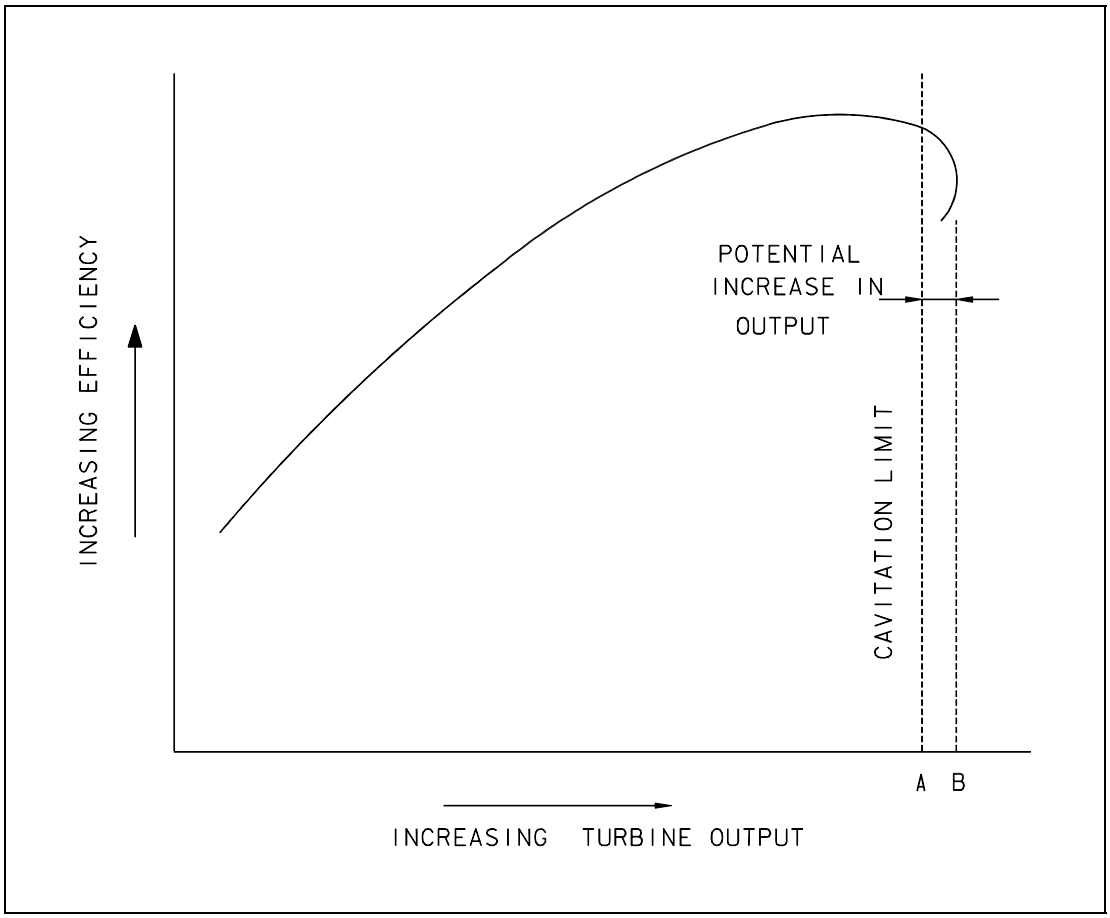

Figure 5-6
Potential Increase of Output

Reprofiling

Reprofiling of runner blades is one option for increasing unit efficiency or decreasing losses associated with cavitation damage beyond historical levels.

Input from the turbine manufacturer is invaluable in making runner modifications. Except for small adjustments, the changes may influence the performance of the machine. This is especially true for pump-turbines where blade modifications at the turbine leading edge will affect pump discharge and pump leading edge modifications will influence turbine performance.

Paint and other thin coatings on the blade runners do not significantly impact efficiency or unit performance unless they are of sufficient thickness to alter the form or contours of the surface.

See Volume 1, Section 4.8 for further discussion on coatings and paints in general.

Runner modifications require a thorough analysis and understanding of the cause of the cavitation pitting and/or the mechanism for efficiency improvements. Basically, four types of modifications may be necessary:

- Leading edge modification
- Training edge modification
- Profile changes
- Addition of anti-cavitation fins (on propeller and Kaplan turbines)

Often, new runner profiles can more easily be adapted for Pelton replacement runners than on other types of turbines such as Francis and Kaplan.

Runner Blade Angle Optimization (Kaplan Turbines)

For Kaplan turbines, the following procedure can help to determine if additional output can be achieved by increasing the runner blade angle. During the test, the runner blade angle will be "off cam" and adjusted manually with the servomotor stroke at its maximum position. A curve of unit output versus runner blade position, similar to Figure 5-5, will indicate whether output is limited by runner blade angle. Changing the runner blade angle can be accomplished by changes to the runner blade linkage; however, disassembly of the turbine and runner is required, and it is generally much more difficult than increasing the wicket gate servomotor stroke.

Runner Stresses

Increasing the turbine output in a unit upgrade project will increase the runner stress; however, evaluating the runner stress is a complicated procedure. Generally, because of safety factors used in the design of older units, increasing turbine output up to 10% can usually be performed without overstressing the runner material. Replacement runners of higher strength stainless steel alloys can be substantially uprated and still be within acceptable stress limits.

Multi-jet units have proved their high efficiency at higher unit loads. However, the more rapid accumulation of stress cycle alterations justify a more conservative runner design. Abrasive water will erode the buckets of a multi-jet turbine more rapidly than in the case of a single jet per runner.[13]

5.4.3 Wicket Gate and Wicket Gate Operating Mechanism

Electric Servomotors[14]

For some applications electric servomotors may be an alternative to more conventional hydraulic systems. The advantages of electric servomotor systems are freedom from dealing with

[13] American Society of Mechanical Engineers, Hydropower Technical Committee, HCI Publications Inc., Kansas City, MO 1996, "*The Guide to Hydropower Mechanical Design"*

[14] EPRI, December 1998 Palo Alto, CA WO5715-01, "*Hydropower Technology Round-up Report, Part 2",* Rehabilitation and Upgrading of Hydro Plants

hydraulic oil, easy maintenance, and relative compactness. In Japan, electric servomotor systems have been developed and implemented to replace oil-based gate operating systems. Over 60 systems have been installed on small and medium-sized Francis turbines. Electric servomotors up to 55 kW are available; this is sufficient for a 5-second gate closure of a 60 MW turbine under a head of 100 m or a 90 MW turbine under a head of 200 m. Reliability has been high, reducing the need for redundant systems; today's systems have a DC battery bank standby only. The basic design was developed in the 1980s and has not changed significantly, but features have been improved with experience.

The need for fast, emergency shutdown is a significant limitation to the application of electric servomotor systems. Wider application seems to require development of a more powerful and compact energy storage system.[15] At present, except for very small units, a modern high pressure hydraulic system with hydraulic servomotors is less costly than electric servomotors.

Modifying Existing Servomotors

Turbine rated output has historically been guaranteed. As a result, older turbine designs typically include an additional 5 to 10% wicket gate servomotor stroke beyond the guaranteed rated output. With the new design tools available, turbine designers probably do not build in this buffer anymore.

Servomotor stroke limits the turbine output by limiting the flow to the unit by restricting wicket gate opening. The method to determine whether servomotor stroke is the limiting factor was previously discussed in conjunction with runner vent limitations. If servomotor stroke limits output, providing a longer servomotor cylinder or shorter piston will increase the maximum wicket gate opening and allow for increased unit output.

Increasing servomotor stroke may also increase the runaway speed; therefore, the existing values for this parameter needs to be evaluated relative to the percentage increase in wicket gate opening. Increasing the wicket gate opening may also change the wicket gate closing tendency and would eliminate the self-closing tendency of the wicket gates from full gate. For a runner blade servomotor, the force required to move the blades may also be increased.

For a servomotor operating at pressures below the design pressure, the load can be increased in proportion to the actual and design pressures. For a servomotor operating at the design pressure, a larger diameter piston may be required in addition to a decrease in piston length.

Methods of increasing servomotor stroke include:

- changing the existing stroke limits
- machining the piston to reduce its length
- machining the servomotor heads to increase stroke

[15] H. Tanaka, S. Sugimoto and H. Tomiyasha, "*Experiences and Developments of Electric Servomotor Systems for Hydraulic Turbine Control"* paper presented at Hydrovision 98 Conference, Reno, NV (July 1998)

- providing new pistons of shorter length
- providing a longer servomotor cylinder
- modifying the wicket gate linkages

5.4.4 Nozzle Assemblies and Deflectors (Pelton Turbines)[16]

One way to increase the output of a Pelton turbine is to enlarge the needle seats. Servomotor operation may be affected because of the change in operating conditions. Stresses in the needle assembly should be calculated if an enlargement is undertaken.

Enlargement of the nozzle seats is limited by the contact point of the needle and nozzle seat. Most needle seats are sized to accommodate some nozzle machining for maintenance which should not significantly affect the contact sealing or interface relationship at small needle openings. A large increase in nozzle diameter will often require a redesign of the nozzle assembly and the needle shaft.

With any increase in unit flow, change[17] in the bearing forces, shaft stresses and runner stresses will result. Likewise, if the unit is operated with unbalanced needle configurations, a runner and shaft stress analysis and non-destructive testing should be undertaken.[18]

It should be noted that some modern bucket designs might not provide optimal performance with older nozzle and casing technology. However, most older units have a lower specific speed and larger buckets than modern runners which is advantageous when jet enlargement is being considered for power upgrades or a new runner for larger jets is required.[19]

An increased jet diameter will have the potential for increased speed rise during a full load rejection. Governor settings should be reviewed if the unit must operate on a small or isolated system. Some units have deflectors that follow just outside the jet stream and, if the nozzle size is increased, the deflector to jet stream clearance must be checked or modified as well as the size and stroke of the deflectors. All highly stressed components of the deflector system should be analyzed.[20]

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[16] M.E. Gass, Waterpower 1997, Proceedings of the International Conference on Hydropower, Vol. 3, ASCE, New York, NY, *"Modernization and Performance Improvements of Vertical Pelton Turbines"*.

[17] M.E. Gass, Waterpower 1997, Proceedings of the International Conference on Hydropower, Vol. 3, ASCE, New York, NY, *"Modernization and Performance Improvements of Vertical Pelton Turbines"*.

[18] M.E. Gass, Waterpower 1997, Proceedings of the International Conference on Hydropower, Vol. 3, ASCE, New York, NY, *"Modernization and Performance Improvements of Vertical Pelton Turbines"*.

[19] M.E. Gass, Waterpower 1997, Proceedings of the International Conference on Hydropower, Vol. 3, ASCE, New York, NY, *"Modernization and Performance Improvements of Vertical Pelton Turbines"*.

[20] M.E. Gass, Waterpower 1997, Proceedings of the International Conference on Hydropower, Vol. 3, ASCE, New York, NY, *"Modernization and Performance Improvements of Vertical Pelton Turbines"*.

5.4.5 Other Hydraulic Components

Stay Ring and Vanes

The modification of the stay ring and vanes can provide significant efficiency gains during unit upgrades. CFD can be used to analyze the existing flow conditions from the spiral case to the stay ring and vanes and to determine efficiency gains from any proposed modifications. If model testing is to be carried out for the upgrade project then any gains estimated by a CFD analysis can be confirmed at that time.

One modification that can be made to the stay ring is the addition of deck plates to increase efficiency by improving the uniformity of flow entering the distributor and changing the angle of the approach flow to the stay vanes. The application of deck plates may not be economically justified in many cases and other solutions should be investigated before proceeding with this type of modification. The same results may be achievable by modifying the stay vane profile by the addition or removal of material from the trailing or leading edges. This is the more common approach.

Hydraulic Pathways

"Smoothing" of hydraulic pathways is another upgrade that can be inexpensive and provide some efficiency gains. A discussion of the various coatings that can be used on turbine components is provided in Section 4, Volume 2. Appropriate coatings applied to the spiral case, stay vanes, wicket gates and draft tube can reduce losses and provide some protection against cavitation and erosion, which increase losses as they "roughen" the surface finish.

Draft Tube Modifications

The draft tube serves to decelerate the water leaving the runner, thereby recovering a significant portion of energy (velocity head) in the water at the discharge of the runner. The draft tube is particularly important for low head high specific speed turbines where the velocity head at the runner exit represents a sizable portion for the total head.

A theoretical draft tube would be a cone with an expansion angle of 6 degrees per side. Some early elbow draft tubes were laid out to approximate this theory. However it has been found that while an overall expansion angle of about 6 degrees is reasonable, the expansion should be minimal in the elbow area, or there should even be some acceleration to prevent separation at the roof of the elbow. The expansion immediately downstream of the runner can be greater than 6 degrees.

Because of the excessive area expansion in the draft tube elbow, many early designs have relatively low efficiency, and limit the potential efficiency increase obtainable for a runner upgrade. There are various methods of mitigating this limitation, including:

- adding concrete in the elbow to reduce its deceleration in the elbow
- adding a splitter vane to minimize separation in the roof of the elbow. (The splitter vane performs a similar function as a turning vane in an abrupt pipe elbow.)

Other older draft tubes such as the sharp heeled (or horseshoe) design have substandard energy recovery characteristics particularly at flows higher than the peak efficiency turbine flow. Draft tube modifications can improve performance.

Draft tube modifications are usually quite costly and should be implemented only after careful study. Comparative model tests should be done to check the incremental benefit of draft tube modification. For lower capacity units, model tests may be too costly. As a minimum, CFD analyses of the draft tube modification should be made.

Draft tubes are covered in more detail in Volume 6 of these Guidelines.

Distributor (Pelton Turbines)[21]

Sizing of a distributor is an exercise in balancing costs of a larger distributor against losses associated with a smaller distributor. A rule of thumb is to size the unit so that at full load, the velocity in the spiral case/distributor is 10% or less of the total unit's velocity head. One area of opportunity for efficiency upgrades is in the unit's needle branching. Older spiral distributors were often constructed in large curved cast sections. Newer units usually have distributors that are constructed of shorter mitered ring sections.

Runner Pit Sizing and Venting (Pelton Turbines)[22]

Pit sizing follows from distributor sizing. Enlarging a runner pit is often impractical and costly. Proper venting prevents the discharged water of the runner from backing up. This is important if the existing design is marginal at full load or higher tailwater levels. The shape of the existing pit is also important. Some manufacturers claim pit shape can effect turbine efficiency as much as several tenths of a percent when compared to a similar sized pit with a more optimum shape.

Tailwater depression systems are sometimes added for vertical Pelton turbines to permit operation under conditions of high tailwater during flood or high runoff periods. Such systems consist of high volume, low pressure air compressors (blowers) and may require modification of

[21] Matthew E. Gass, PE, Waterpower 1997 Proceedings of the International Conference on Hydropower, Vol. 3, ASCE, New York, NY, *"Modernization and Performance Improvements of Vertical Pelton Turbines"*.

[22] Matthew E. Gass, PE, Waterpower 1997, Proceedings of the International Conference on Hydropower, Vol. 3, ASCE, New York, NY, *"Modernization and Performance Improvements of Vertical Pelton Turbines"*.

the shaft seal and wheel pit to minimize air loss during operation. Modifications may also be required to the tailrace structure to minimize loss of depression air.

5.4.6 Shaft

The turbine shaft may limit turbine output increase by its minimum diameter and allowable stress of the material. As a very preliminary evaluation, the allowable shaft output can be calculated by the following formula.

$$\text{Maximum output, kW} = \frac{\tau N(d_o^4 - d_I^4)}{d_o\ 430{,}448}$$

where:

N	=	unit speed, rpm
d_o	=	minimum outer diameter of shaft, inches
d_I	=	inner diameter of shaft, inches, and
τ	=	allowable shear stress, lb_f/in^2 = 1/6 yield stress, psi of the shaft material (use manufacturer's values or obtain from standard tables).

If the above formula indicates that shaft stress will limit the maximum output, a more detailed evaluation can be made which accounts for axial thrust as well as lateral load on the runner. For such an analysis it is usual to allow combined stresses (Von Mises) to reach 1/3 yield stress. Extensive literature is available on how to perform shaft and coupling stress calculations. There are standards for sizing and manufacturing tolerances, such as ANSI/IEEE Standard 810. USBR Engineering Monograph No. 20 has a formula for estimating shaft sizes.

In addition to evaluating steady state conditions, transient conditions of an upgraded runner should also be investigated. The investigation should include turbine start-up when higher torque levels occur for short periods. Generally, however, the safety factors used in shaft stress calculations will allow a limited increase of capacity.

If the shaft capability limits turbine output, the shaft capability can be increased by a larger diameter shaft of the same material or by the same diameter shaft and a higher strength material. A new shaft of larger diameter would probably require a new bearing and/or shaft seal. The most cost-effective alternative may be to limit the capacity upgrade to the maximum capability of the existing shaft.

5.4.7 Governing System

Modern governors and electronic controls can enhance the capability of a unit to operate at maximum efficiency or to maintain constant discharge, under changing head conditions.[23] Modern digital equipment, with their self-diagnostic capabilities and enhanced communication tools, can greatly reduce the human effort in operating and monitoring a hydro plant while enhancing reliability. Some upgrade projects have focused primarily on governors and controls.

Control of a Remote Plant in a Small System[24]

One example of the application of modern digital governor technology is in the control of mult-jet Pelton turbines. If the governor is programmed to control each needle independently, the turbine may suffer power swings when shifting between two- and four- or between four- and six-valve operation. These power swings may exceed 10% of unit capacity for the combination of a long tunnel and a small load.

Special digital governor logic can be provided to eliminate power swings. A governing system upgrade at the Bradley Lake Plant in Alaska is believed to be the first time such logic has been applied to governing impulse turbines. Adjustments to the needles keep flow and power nearly constant through the transition period while the needles are being opened or closed.

Controls Upgrades at Remotely-Operated Plants[25]

Replacing antiquated, mechanical/analog plant controls with digital controls can improve operating efficiency, permit better coordination with other plants, and produce a range of operational information. A new digital system for a multi-unit, remotely operated plant can be designed to: optimize load among the plant's units; perform water flow calculations for each unit, including measurement of water levels and head losses; record events and timing; provide information on operating conditions and automatic report printouts of energy values; and adapt to the remote control center commands.

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[23] O. Moeller, Panel Session (audiotaped): "*Rehabitation II - Lessons Learned",* HydroVision 98 Conference, Reno, NV (July 1998)

[24] EPRI, December 1998, Palo Alto, CA WO5715-01, *"Hydropower Technology Round-up Report, Part 2,"* Rehabilitation and Upgrading of Hydro Plants

[25] EPRI, December 1998, Palo Alto, CA WO5715-01, *"Hydropower Technology Round-up Report, Part 2,"* Rehabilitation and Upgrading of Hydro Plants

5.5 Turbine Runner Replacement

Modernization Opportunities (Step 4-5)	Benefits of Modernization (Step 4-5, Volume 1)
Further Studies Required	
Impacts of Modernization on Other Equipment	Other Equipment that Limits Modernization
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

Section 5.5 provides a summary of the preliminary calculations and main issues for evaluating runner replacement as an upgrade option. Any upgrade potential determined from this high level review should be entered into the "Equipment Modernization Opportuntiies" worksheet (Table 5-1) as a possible upgrade opportunity.

5.5.1 General

The primary goal of turbine upgrade is to increase the turbine efficiency and/or maximum power output. An increase in the efficiency at full load (smaller of 100% wicket gate opening or generator capacity) will increase the full load power; however more significant increases in power are usually accomplished by increasing the maximum turbine flow.

Maximum turbine flow can be increased by trimming the outlet edges of the runner blades and/or increasing the servomotor stroke as previously discussed in Section 5.4. **More dramatic improvements can usually be accomplished by installing a new runner of a modern design.**

With a new replacement runner design, it is generally possible to increase both the efficiency and the maximum flow as well as improve cavitation performance. There are no specific rules; the magnitude of the increases depends on the design of the replacement runner. It must be realized that increases in flow are often a compromise. With higher flows there are greater head losses in the turbine water passages which translate to reduced efficiency. This is illustrated in Figure 5-7.

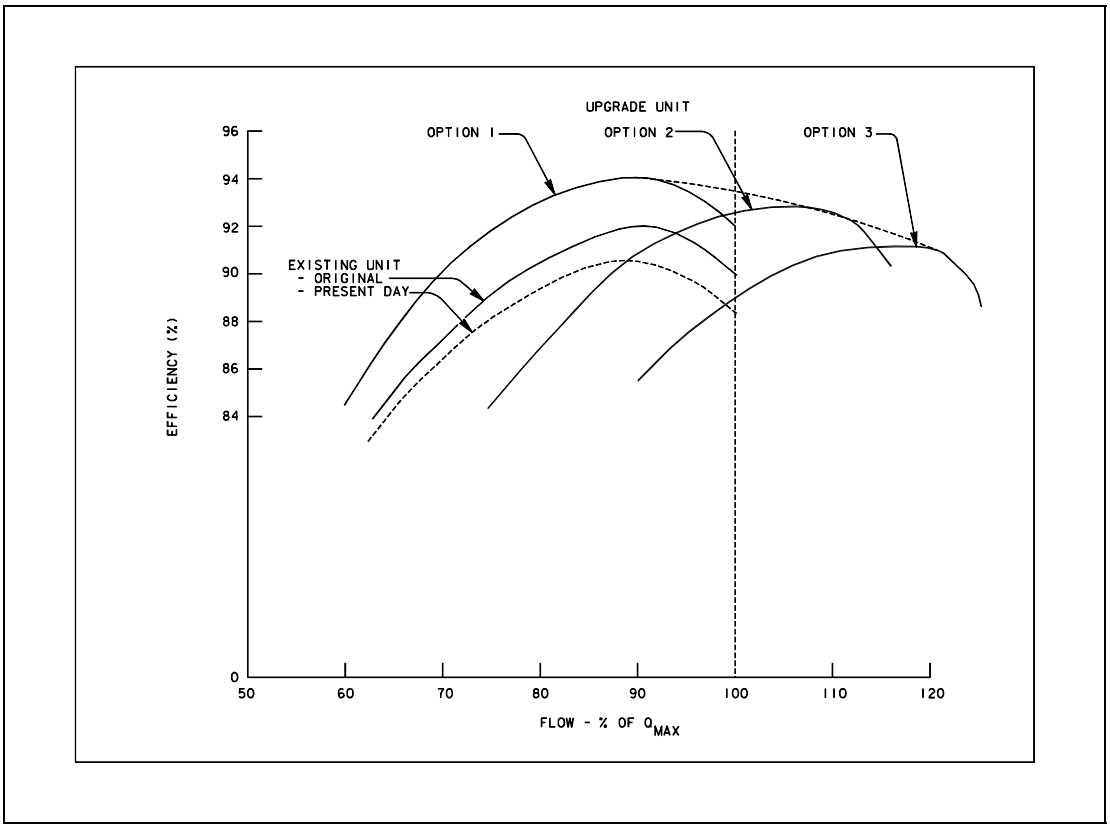

Figure 5-7
Turbine Efficiency vs Unit Flow

Unless the existing turbine suffers from severe cavitation damage requiring the turbine to be derated, it will be possible to provide an upgraded runner with the same maximum flow capacity as the existing turbine, but with increased efficiency. Increases in flow are not straightforward, as factors such as cavitation limits come into play, and as mentioned above the higher flows will reduce the efficiency gains. For substantial flow increases the new runner may result in a lower unit efficiency than the existing turbine. The selection of optimum flow is often an economic study, which trades off efficiency and power.

The analysis of turbine upgrade potential makes use of several turbine parameters including specific speed, unit speed, unit discharge and cavitation coefficient. Several parameters are used in the industry, and there is no general consensus among owners, manufacturers and engineers as to standardized terminology. The parameters below are used in the subsequent analysis and a comparison of other parameters are presented in Table 5-6. The equations are numbered for clarity.

- Specific speed (power based) (N_s) = $nP^{0.5}/H^{1.25}$ [5-1]

- Specific speed (flow based) (N_Q) = $nQ^{0.5}/H^{0.75}$ [5-2]

- Optimum specific speed ($N_{Q\,opt}$) = $nQ_{opt}{}^{0.5}/H^{0.75}$ [5-3]

- Unit speed (N_{11}) = $Dn/H^{0.5}$ [5-4]

- Unit discharge (Q_{11}) = $Q/(D^2H^{0.5})$ [5-5]

- Cavitation coefficient (σ) = $(H_a - H_v - H_s)/H$ [5-6]

Where:

n = turbine rotational speed (rpm)
P = turbine power (kW)
Q = discharge units (m^3/s)
H = net head (m) ("design" and "rated" head have the same meaning)
Q_{opt} = peak efficiency discharge (m^3/s)
D = runner discharge diameter (m)
H_a = atmospheric pressure (m)
H_v = vapor pressure of water (m)
H_s = elevation of the reference point on the runner minus elevation of tailwater level (m)

For propeller/Kaplan units the accepted reference elevation for cavitation coefficient calculations is the centreline of the blades. For Francis units there is no universally accepted reference elevation. The IEC 193 model test code specifies the use of the distributor centreline but some turbine suppliers use other points within the unit as a reference. Often, the bottom of the runner blade is used as a reference elevation. In any specification developed for Francis turbine upgrade work this reference elevation should be clearly stated.

See Figure 5-8 and Table 5-7.

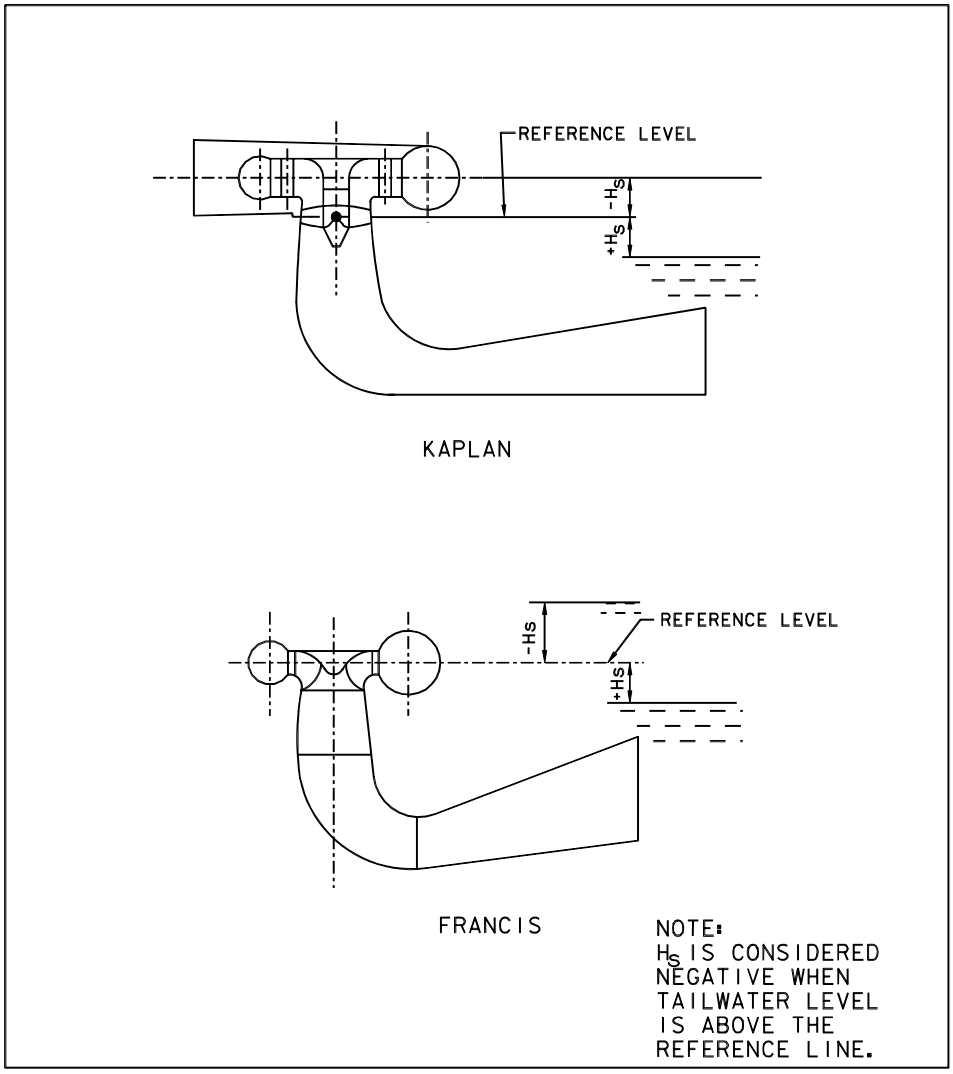

Figure 5-8
Submergence (Hs) for Kaplan and Francis Turbines

Table 5-6
Turbine and Pump-Turbine Parameters

Parameter	Formula	Units		Conversion (metric to US Customary)	Other Conversions	Notes
		US Customary	metric (or SI)			
Specific speed (power based) - N_s	$\frac{nP^{0.5}}{H^{1.25}}$	rpm, hp, ft	rpm, kW, m	N_s (US) = 0.262 N_s (metric)	-	(1)
Specific speed (flow based) - N_Q	$\frac{nQ^{0.5}}{H^{0.75}}$	rpm,gpm (or cfs), ft	rpm, m^3/s, m	N_Q (US, gpm) = 51.6 N_Q (metric) N_Q (US, cfs) = 2.44 N_Q (metric)	N_Q (US, gpm) = $2734\omega_s$	(2)(3)
Specific speed (non-dimensional) - ω_s	$\frac{\omega Q^{0.5}}{(gH)^{0.75}}$	rad/s, cfs, ft	rad/s, m^3/s, m			
Unit discharge - Q_{11}	$\frac{Q}{D^2H^{0.5}}$	cfs, ft	m^3/s, m	Q_{11} (US) = 1.81. Q_{11} (metric)	Q_{11} (US) = 5.68 Q_{ed}	
Unit discharge (non-dimensional) - Q_{ed}	$\frac{Q}{D^2(gH)^{0.5}}$	cfs, ft	m^3/s, m	-	-	
Unit power - P_{11}	$\frac{P}{D^2H^{1.5}}$	hp, ft	kW, m	P_{11} (US) = 0.021 P_{11} (metric)	P_{11} (US) = 0.644 P_{ed}	(4) (5)
Unit power (non-dimensional) - P_{ed}	$\frac{P}{\rho D^2(gH)^{1.5}}$	ft-lb/s, slugs/ft^3,ft	W, kg/m^3,m	-	-	
Unit speed - N_{11}	$\frac{Dn}{H^{0.5}}$	ft, rpm	m, rpm	N_{11} (US) = 1.81 N_{11} (metric)	N_{11} (US) = 54.1 N_{ed} $N_s = N_{11} P_{11}^{0.5}$ $N_Q = N_{11} Q_{11}^{05}$	
Unit speed (non-dimensional) N_{ed}	$\frac{\omega D}{(gH)^{0.5}}$	rad/s, ft	rad/s, m	-	-	
Velocity ratio (phi) - ϕ (non-dimensional)	$\frac{Dn}{153H^{0.5}}$	ft, rpm		-	$\Phi = \frac{N_{11}(US)}{153}$	
	$\frac{Dn}{84.5H^{0.5}}$		m, rpm		$\Phi = \frac{N_{11}(Metric)}{84.5}$	

Potential for Improvements

Parameter	Formula	Units		Conversion (metric to US Customary)	Other Conversions	Notes
		US Customary	metric (or SI)			
Energy coefficient (non-dimensional) - $E_{\omega d}$	$\frac{gH}{(\omega D)^2}$	ft, rad/s	m, rad/s	-	$E_{\omega d} = \frac{1}{8\Phi^2}$	
Discharge coefficient (non-dimensional) - $Q_{\omega d}$	$\frac{Q}{\omega D^3}$	cfs, rad/s, ft	m^3/s, rad/s, n	-	$\omega_s = \frac{Q_{\omega d}^{0.5}}{E_{\omega d}^{0.75}}$	
Power coefficient (non-dimensional) - $P_{\omega d}$	$\frac{P}{\rho \omega^3 D^5}$	ft-lb/sec, slugs/ft^3, rad/s, ft	W, kg/m^3, rad/s, m	-		
Cavitation coefficient (non-dimensional) - Sigma (σ)	$\frac{H_a - H_v - H_s}{H}$	ft	m	-	-	

n = speed
P = power
H = head
Q = discharge
D = runner diameter
g = acceleration of gravity
ρ = mass density
ω = speed
H_a = atmospheric pressure
H_v = vapour pressure
h_s = suction head

Notes:

1. The power based specific speed is more common in the US Customary system of units.
2. In the US Customary system, specific speed with flow in gpm is used for (pump-turbine) pump mode operation.
3. Except for pump mode specific speed, the flow based specific speed is more commonly used in the metric system.
4. Unit power (P_{11}) is also referred to as HP_{11} (US Customary units) or kW_{11} (metric).
5. Unit power is more common in the US Customary system of units.

Table 5-7
Values of Atmospheric Pressures (H_a) and Vapor Pressure (H_v)

Atmospheric Pressure			
Altitude Z (feet)	H_a (feet of H_20)	Altitude Z (meters)	H_a (m of H_20)
0	33.959	0	10.351
500	33.35	500	9.751
1,000	32.85	1,000	9.180
1,500	32.16	1,500	8.637
2,000	31.57	2,000	8.120
2,500	31.00	2,500	7.628
3,000	30.00	3,000	7.160
3,500	29.88	3,500	6.716
4,000	29.33	4,000	6.295
4,500	28.79		
5,000	28.25		
5,500	27.73		
6,000	27.21		
6,500	26.70		
7,000	26.20		
7,500	25.71		
8,000	25.22		
8,500	24.74		
9,000	24.27		
9,500	23.81		
10,000	23.35		

Water Properties			
Temperature Tw (°F)	H_v (feet of H_20)	Temperature Tw (°C)	H_v (m of H_20)
40	0.28	5	0.089
50	0.41	10	0.125
60	0.59	15	0.174
70	0.84	20	0.239
80	1.17	25	0.324

5.5.2 Francis Runner Upgrade

The peak model efficiency for a new modern Francis turbine is shown on Figure 5-9. Efficiencies as high as 95% have been reached. However, by installing a new runner in an existing turbine, it is unlikely that efficiency values as high as those shown on Figure 5-9 will be achieved. This is because the losses in the turbine are not made up only of losses in the runner, but also include the spiral case, the stay vanes, wicket gates and draft tube. At typical breakdown of losses is shown in Table 5-8.

Table 5-8
Breakdown of Losses in a Francis Unit

	Lower Head		
Specific Speed ($N_{Q\ opt}$)	30	60	90
- runner hydraulic losses	35%	35%	35%
- disc friction loss	15%	7%	2%
- runner seal losses	10%	8%	3%
- spiral case losses	10%	15%	15%
- stay vane losses	10%	10%	10%
- wicket gate losses	15%	15%	15%
- draft tube losses	5%	10%	20%

The existing spiral case, stay vanes, wicket gates and draft tube may be of an outdated, less than optimum design. Modifications to these components are often not cost effective and if done will usually not result in performance equal to that of a modern design. The spiral case may be smaller than a modern design, increasing friction losses; the stay vanes may have an improper angle causing incidence losses; the wicket gates may have a less than optimum shape; the velocity through the stay vanes and wicket gates can be higher than for a modern design; and the draft tube may be less efficient than a modern draft tube.

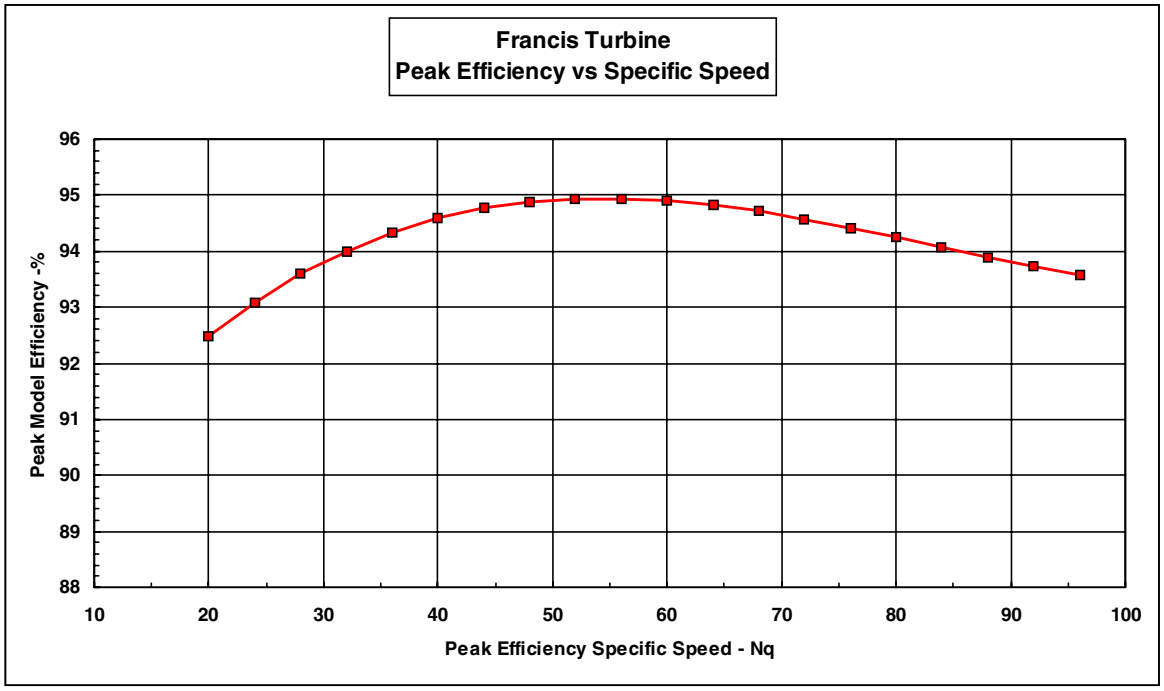

Figure 5-9
Francis Turbine
Peak Efficiency vs Specific Speed

To estimate the upgrade potential of a Francis turbine, the dimensions of the existing turbine should be compared to a modern design with the same rotational speed (n) and similar design parameters. The modern design information may be estimated from various published literature. A methodology is set out below. The formulae are from "Modern Trends in Selecting and Designing Francis Turbines" by F. De Sievo, F. De Leva[26] and "Designing Francis Turbines: Trends in the Last Decade" by A. Lugaresi and A. Massa.[27]

Given the parameters of existing unit:

- head (H)
- power (P)
- speed (n)

[26] F. De Siervo, F. De Leva, "*Modern Trends in Selecting and Designing Francis Turbines",* Water Power & Dam Construction, August 1976, pp. 28-35.

[27] A. Lugaresi, A. Massa, "*Designing Francis Trubines: Trends in the Last Decade"*, Water Power & Dam Construction, November 1987, pp. 23-28.

Calculate the specific speed, unit speed, runner diameter, spiral case inlet diameter, wicket gate height, wicket gate circle diameter and distance from the distributor centerline to the bottom of the band for modern or upgrade turbines:

Specific speed (N_s) = $\frac{nP^{0.5}}{H^{1.25}}$ [from Equation 5-1]

Unit speed (N_{11}) based on an "experience curve" = $24.8 + 0.231\ N_s$ [5-7]

Runner discharge diameter (D) = $\frac{N_{11}H^{0.5}}{n}$ [from Equation 5-4]

Spiral case inlet diameter (A) = $D\ (1.2 - 19.56/N_s)$ [5-8]

Wicket gate height (I) = $D\ (0.1 + 0.00065\ N_s)$ [5-9]

Wicket gate circle diameter (c) = $D\ (0.79+81.75/N_s)$ [5-10]

Distance from the distributor centreline to the bottom of the band (y) = $D\ (-0.05 + 42/N_s)$ for $50<N_s<110$ [5-11]

= $D/(3.16 -0.0013\ N_s)$ for $N_s \geq 110$ [5-12]

(a) Efficiency Increase

An initial estimate of the efficiency of an upgraded Francis turbine with the same (rated) full load flow as the existing turbine can be determined as follows:

4. Determine the full load flow of the existing turbine (Q_{fl1}) at design head, either from site test data or calculating the flow from the nameplate data, assuming a full load turbine efficiency of 88%.

5. Assume peak efficiency flow ($Q_{opt\ 1}$) equals 0.9 x Q_{fl1}. Calculate $N_{Q\ opt}$ using Equation 5-3.

6. From Figure 5-9 determine the model efficiency (E_{mi}) of a new turbine with the same specific speed.

7. If the spiral case inlet diameter for the existing turbine (A_e) is different than that for the new turbine (A_i), adjust the model efficiency by the following:

$\Delta Eff_1 = [1 - (A_i/A_e)^5] \times 0.7\%$ [5-13]

8. If the product of the wicket gate height (H_e) and the wicket gate circle diameter (C_e) for the existing turbine is less than the product of wicket gate height (H_i) and the wicket gate circle diameter (C_i) for the new turbine, adjust the model efficiency by the following:

$$\Delta Eff_2 = \{1 - [(H_i \times C_i / H_e \times C_e)]^2\} \times 0.7\% \quad [5\text{-}14]$$

9. If nothing is known about how well the stay vane angle matches the incidence angle of approach flow, adjust the model efficiency by:

$$\Delta Eff_3 = -0.5\% \quad [5\text{-}15]$$

10. Adjust the model efficiency to allow for a less than optimum draft tube efficiency, as follows:

- Moody draft tube $\Delta Eff_4 = -0.8\%$
- Conical draft tube with low cone $\Delta Eff_4 = -0.8\%$
- Sharp heeled draft tube $\Delta Eff_4 = -1.4\%$
- Elbow draft tube (old design) $\Delta Eff_4 = -1.0\%$
- Elbow draft tube (before 1960) $\Delta Eff_4 = -0.5\%$
- Elbow draft tube (before 1980) $\Delta Eff_4 = -0.2\%$
- Elbow draft tube (after 1980) $\Delta Eff_4 = 0\%$

Different draft tube configurations are illustrated on Figure 5-10.

11. Calculate effective model efficiency (E_m)

$$E_m = E_{mi} + \Delta Eff_1 + \Delta Eff_2 + \Delta Eff_3 + \Delta Eff_4 \quad [5\text{-}16]$$

12. Calculate prototype efficiency (E_p) from model efficiency plus 2/3 of step-up calculated from the Moody formula (a common scaling formula used in the industry).

$$E_{p1} = E_m + (0.67 \times (1-E_m/100) (1-\left(\frac{1.1}{D}\right)^{0.2}) \times 100) \quad [5\text{-}17]$$

Where D is the runner discharge diameter in feet.

(b) Power Increase

As mentioned above power increase is somewhat more difficult to estimate. The relationship of unit speed and unit discharge for Francis turbine is shown on Figure 5-11. The experience "band" for new turbines is shown. To increase the flow capacity of an existing turbine, a turbine on the high side of the band often needs to be designed. The result is a design which usually has a more rapid decrease in efficiency at flows above and below the peak efficiency point. The turbine may also have higher pressure pulsations at part load. The upper flow limit is governed generally by experience, as well as cavitation considerations.

In general cavitation limits can be increased by:

- Increasing the number of blades - this can also decrease efficiency.
- Lengthening the band and the blades - this may require discharge ring modifications
- Lengthening the blades by extending the band into the draft tube - this eliminates the requirement for draft tube modifications but results in a decrease in runner discharge diameter.

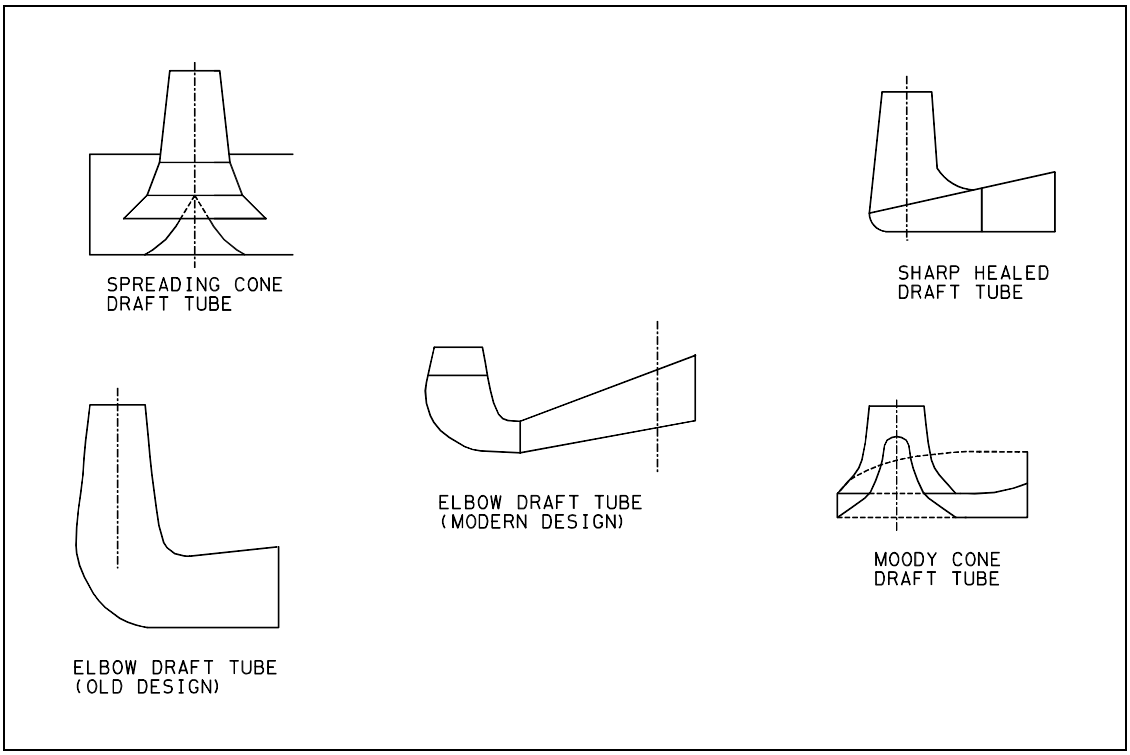

Figure 5-10
Draft Tube Configurations

The general approach to determining the maximum power capability of the upgraded runner would be:

1. Calculate unit speed (N_{11}) using Equation 5-4.

2. Determine the upper limit $Q_{n(opt)}$ for an upgraded runner using Figure 5-11 as a guide or from the relationship:

   Upper limit $Q_{11\ opt} = 0.03N_{11} - 0.09$ [5-18]

3. Calculate Q_{opt} for the runner using Equation 5-5.

4. Assuming full load flow (Q_{fl}) = $Q_{opt}/0.9$, calculate full load specific speed (N_Q) using Equation 5-2.

5. Check the required setting (H_s) from the relationship:

   where,

   H_s = $H_a - H_v - \sigma H$ [from Equation 5-6]

   σ = $[(N_Q^{1.64})/6500] - 0.02$ [5-19]

   If the required setting is lower than the actual runner setting, reduce the flow until the setting is satisfactory.

6. Once the full load flow is established, full load power can be calculated using Equation 5-21 (provided in the next section), assuming a turbine efficiency of 90%.

   Peak efficiency flow $Q_{opt\ 2}$ can be assumed as Q_{fl} x 0.9. The peak efficiency can be estimated from the value determined in (a) above for no increase in flow and from the following formula:

$$E_{p2} = E_{p1} + [1 - \left(\frac{Q_{opt2}}{Q_{opt1}}\right)^2] \times 0.8\ (100 - E_{p1}) \quad [5\text{-}20]$$

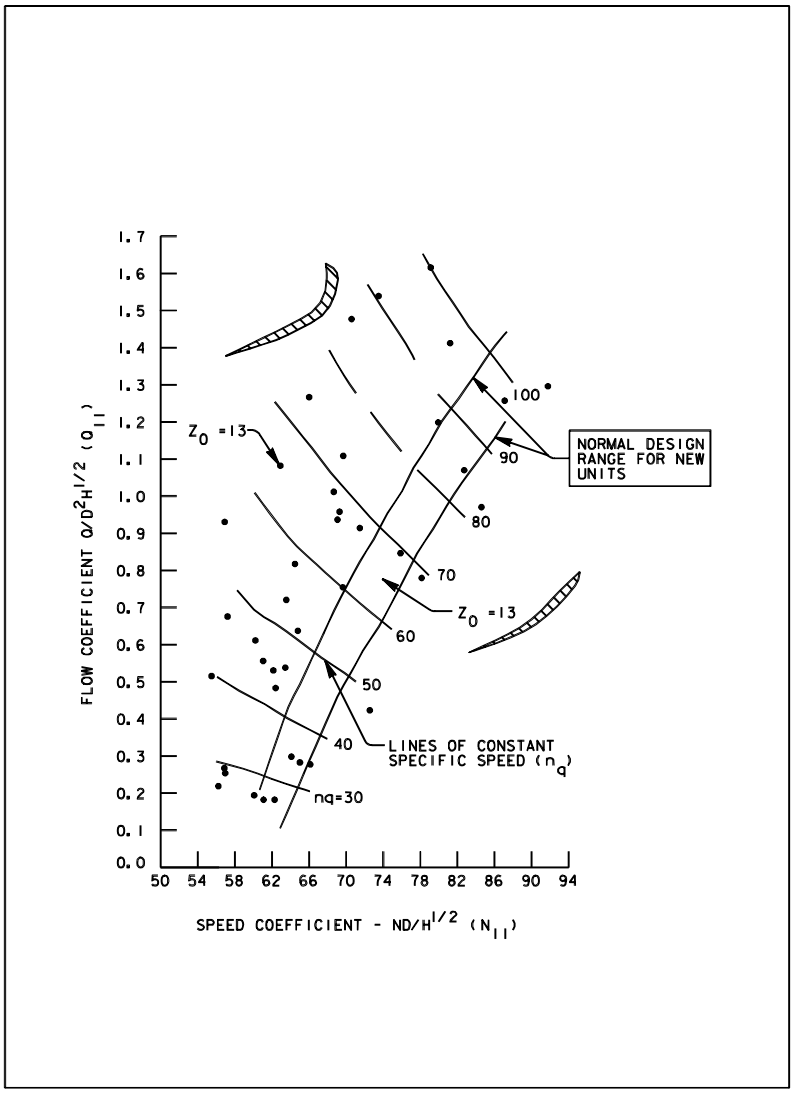

Figure 5-11
Design Points for Recent Replacement Francis Runners (Voith)
"Challenges in the Design and Manufacture of Small Replacement Runners," Alan Roth, Voith. Presented at Waterpower '91. Used with Permission.

(c) Compare Upgrade with Existing Turbine

The maximum capacity for the upgraded runner at rated and maximum head can be calculated by the following equations:

At Rated Head

$$P_r = 0.0846\, Q_{max}\, H_r\, \eta_r \quad \text{(US customary units)} \quad [5\text{-}21a]$$

$$P_r = 9.8\, Q_{max}\, H_r\, \eta_r \quad \text{(metric units)} \quad [5\text{-}21b]$$

At Maximum Head if $Q_m = Q_{max}$

$$P_{max} = 0.0846\ Q_m\ H_m\ \eta_m \cong 0.0846\ Q_{max}\ H_m\ \eta_r$$
(US customary units) [5-22a]

$$P_{max} = 9.8\ Q_{max}\ H_m\ \eta_m \cong 9.8\ Q_{max}\ H_m\ \eta_r \text{ (metric units)} \quad [5-22b]$$

where

P_r = maximum turbine output at rated head, kW,

P_{max} = maximum turbine output at maximum head, kW,

Q_{max} = maximum runner discharge at rated head, ft^3/s, (m^3/s)

Q_m = maximum runner discharge at maximum head, ft^3/s, (m^3/s)

H_r = rated net head, ft, (m)

H_m = maximum net head, ft, (m)

η_r = upgraded runner efficiency at rated conditions, expressed as a decimal

η_m = upgraded runner efficiency at maximum head conditions, expressed as a decimal

(Assumes specific weight of water, 62.4 lb/ft^3.)

The turbine upgrading potential is determined by comparing the existing turbine output and the output of the upgraded runner as follows:

$$\Delta P = P_r - P_{r,\,old} \quad [5\text{-}23]$$

Similarly, increased efficiency and discharge can be calculated as follows:

$$\Delta\eta = \eta_r - \eta_{r,old} \quad [5\text{-}24]$$

and

$$\Delta Q = Q_{max} - Q_{max,\,old} \quad [5\text{-}25]$$

Following implementation, turbine performance can be verified by field tests.

The performance of the existing turbine which includes the maximum output, ($P_{r,old}$), maximum discharge, ($Q_{max,old}$), and corresponding efficiency, (η_{old}), can be determined by the following:

- Nameplate data
- Previous model test or field test results
- New field tests

Section 4.5, Volume 2 discusses the evaluation of the existing turbine performance in more detail.

5.5.3 Kaplan and Propeller Runner Upgrade

The possible increases in efficiency and/or power for a Kaplan runner upgrade can be estimated using a similar approach as discussed in Section 5.5.2 for a Francis runner upgrade. The peak model efficiency of a Kaplan turbine is shown on Figure 5-12, and typical breakdown of losses is shown in Table 5-9:

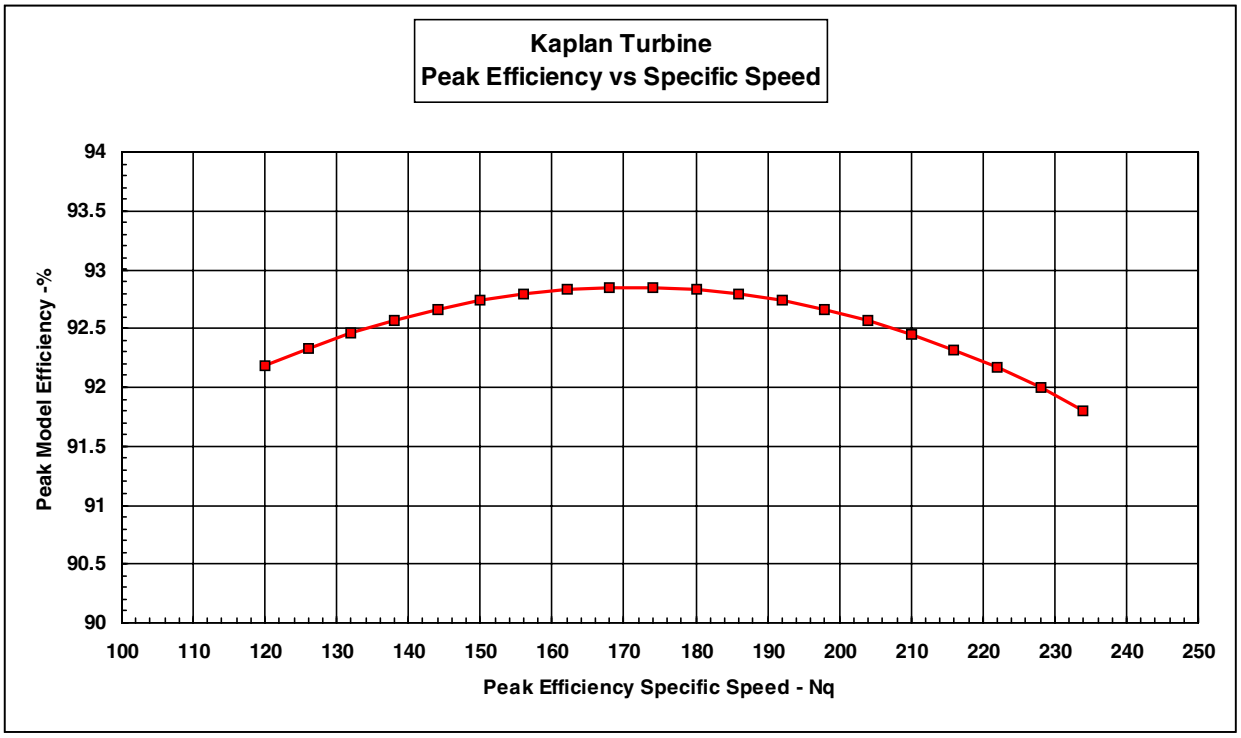

Figure 5-12
Kaplan Turbine - Peak Efficiency vs. Specific Speed

Table 5-9
Breakdown of Losses in a Kaplan Unit

Component	% of Total Losses
Runner hydraulic losses	35%
Leakage losses	5%
Spiral or semi-spiral casing losses	10%
Stay vane losses	10%
Wicket gate losses	10%
Draft tube losses	25%
Mechanical losses	5%

To estimate the upgrade potential of a Kaplan turbine, the dimensions of the existing turbine in comparison to a modern design with the same rotational speed and similar design parameters should be given. This may be estimated from various published literature. The formulae below are taken primarily from "Modern Trends in Selecting and Designing Kaplan Turbines" by F. De Siervo and F. De Leva.[28]

Calculate specific speed, unit speed, runner diameter, semi-spiral inlet area or spiral case inlet diameter, wicket gate height, and wicket gate circle diameter.

- Specific speed ($N_{s)}$ = $\frac{nP^{0.5}}{H^{1.25}}$ [From Equation 5-1]
- Unit speed (N_{11}) - based on an "experience curve" = $66.8 + 0.136\ N_s$ [5-26]
- Runner diameter (D) = $\frac{N_{11}H^{0.5}}{n}$ [From Equation 5-4]
- Hub diameter (D_h) = $D\ (0.25 + 94.64/N_s)$ [5-27]
- Wicket gate height (I) = $D\ (0.44 - 21.47/N_s)$ [5-28]
- Wicket gate circle diameter (C) = $D\ (1.19 + 4.69/N_s)$ [5-29]
- Spiral case inlet diameter (A) = $0.4D\ N_s^{0.2}$ [5-30]
- Semi-spiral case inlet width (W) = $2.8D$ [5-31]
- Semi-spiral case inlet height (L) = $1.7D$ [5-32]

[28] F. De Siervo, F. De Leva, "*Modern Trends in Selecting and Designing Kaplan Turbines"*, Water Power & Dam Construction, December 1977, pp. 51-56 and January 1998, pp. 52-58.

Potential for Improvements

(a) Efficiency Increase

An initial estimate of efficiency of an upgraded turbine with the same full load flow as the existing turbine can be estimated as follows:

1. Determine the full load flow of the existing turbine (Q_{fl1}) at design head, either from site test data or calculating the flow from the nameplate data, assuming a full load turbine efficiency of 88 % using Equation 5-21.

2. Assume peak efficiency flow ($Q_{opt\ 1}$) equals 0.65 x Q_{fl1}. Calculate $N_{s\ opt}$ using Equation 5-3.

3. From Figure 5-12 determine the model efficiency (E_{mi}) of a new turbine with the same specific speed.

4. If the semi – spiral case inlet area (A_e = wxL) or spiral case inlet area ($A_e=\pi A^2/L$) for the existing turbine is different than that for the new turbine (A_i), adjust the model efficiency by the following:

$$\Delta Eff_1 = [1 - (A_i/A_e)^2] \times 0.8\% \qquad [5\text{-}33]$$

5. If the product of the wicket gate height (H_e) and the wicket gate circle diameter (C_e) for the existing turbine is less than the product of wicket gate height (H_i) and wicket gate circle diameter (C_i) for the new turbine, adjust the model efficiency by the following:

$$\Delta Eff_2 = \{1-[(H_i \times C_i)/(H_e \times C_e)]^2\} \times 0.7\% \qquad [\text{From Equation 5-14}]$$

6. If nothing is known about how well the stay vane angle matches the incidence angle of approach flow, adjust the model efficiency by:

$$\Delta Eff_3 = -0.3\% \qquad [5\text{-}34]$$

7. Adjust the model efficiency to allow for the less than optimum draft tube efficiency, as follows:

Moody draft tube	$\Delta Eff_4 = -1.2\ \%$
Conical draft tube with low cone	$\Delta Eff_4 = -1.2\ \%$
Sharp heeled draft tube	$\Delta Eff_4 = -2.0\ \%$
Elbow draft tube (old style)	$\Delta Eff_4 = -1.5\ \%$
Elbow draft tube (before 1960)	$\Delta Eff_4 = -1.0\ \%$
Elbow draft tube (before 1980)	$\Delta Eff_4 = -0.5\ \%$
Elbow draft tube (after 1980)	$\Delta Eff_4 = 0\ \%$

Different draft tube configurations are illustrated in Figure 5-10.

8. Calculate effective model efficiency (E_m)

$$E_m = E_{mi} + \Delta Eff_1 + \Delta Eff_2 + \Delta Eff_3 + \Delta Eff_4 \qquad \text{[From Equation 5-16]}$$

9. Calculate prototype efficiency (E_{p1}) from model efficiency plus 2/3 of step-up calculated from the Moody formula.

$$E_{p1} = E_m + (0.67 \times (1 - E_m/100)(1 - \left(\frac{1.1}{D}\right)^{0.2}) \times 100) \qquad \text{[From Equation 5-17]}$$

where D is the runner diameter in feet

(b) Power Increase

Power levels are generally governed by cavitation considerations. For the calculated plant sigma the maximum unit discharge (Q_{11}) for plant can be estimated from Figure 5-13. From the maximum unit discharge, the turbine full load flow and power can be determined, assuming an efficiency of approximately 90%.

The peak efficiency can be estimated from the value determined in (a) above for no increase in flow, and the following formula:

$$E_{p2} = E_{p1} + [1 - \left(\frac{Q_{opt2}}{Q_{opt1}}\right)^2] \times 0.8 \times (100 - E_{p1}) \qquad \text{[From Equation 5-20]}$$

(c) Propeller Runner Upgrade

The possible increases in efficiency and/or power for a fixed blade propeller runner upgrade can be estimated using the same formulae and graphs as for a Kaplan turbine, except that the peak efficiency flow (Q_{opt}) should be assumed as 0.95 times the full load flow (Q_{fl}). For the same runner diameter, speed and setting relative to tailwater level, the maximum flow for a propeller runner, as limited by cavitation, can be somewhat higher than a Kaplan runner, because of the ability to fully optimize the runner blade design for operation at one fixed angle. Also, the propeller runner can have a smaller hub, which increases the net available flow area at the runner centreline. Therefore the unit discharge values for a Kaplan runner in Figure 5-13, can be increased approximately 5% when evaluating a propeller runner.

For propeller turbines, which operate in the 50 to 100 ft range, it may be possible to obtain substantial increase in flow and power by installing a runner with six to eight blades in mixed (diagonal) flow configuration. The increased number of blades and added area of each blade provides better cavitation performance when compared to a conventional propeller or Kaplan turbine. Maximum power levels can be 15% higher than that of a Kaplan runner. Of course, with the higher flows, there are increased losses, which reduce peak efficiency.

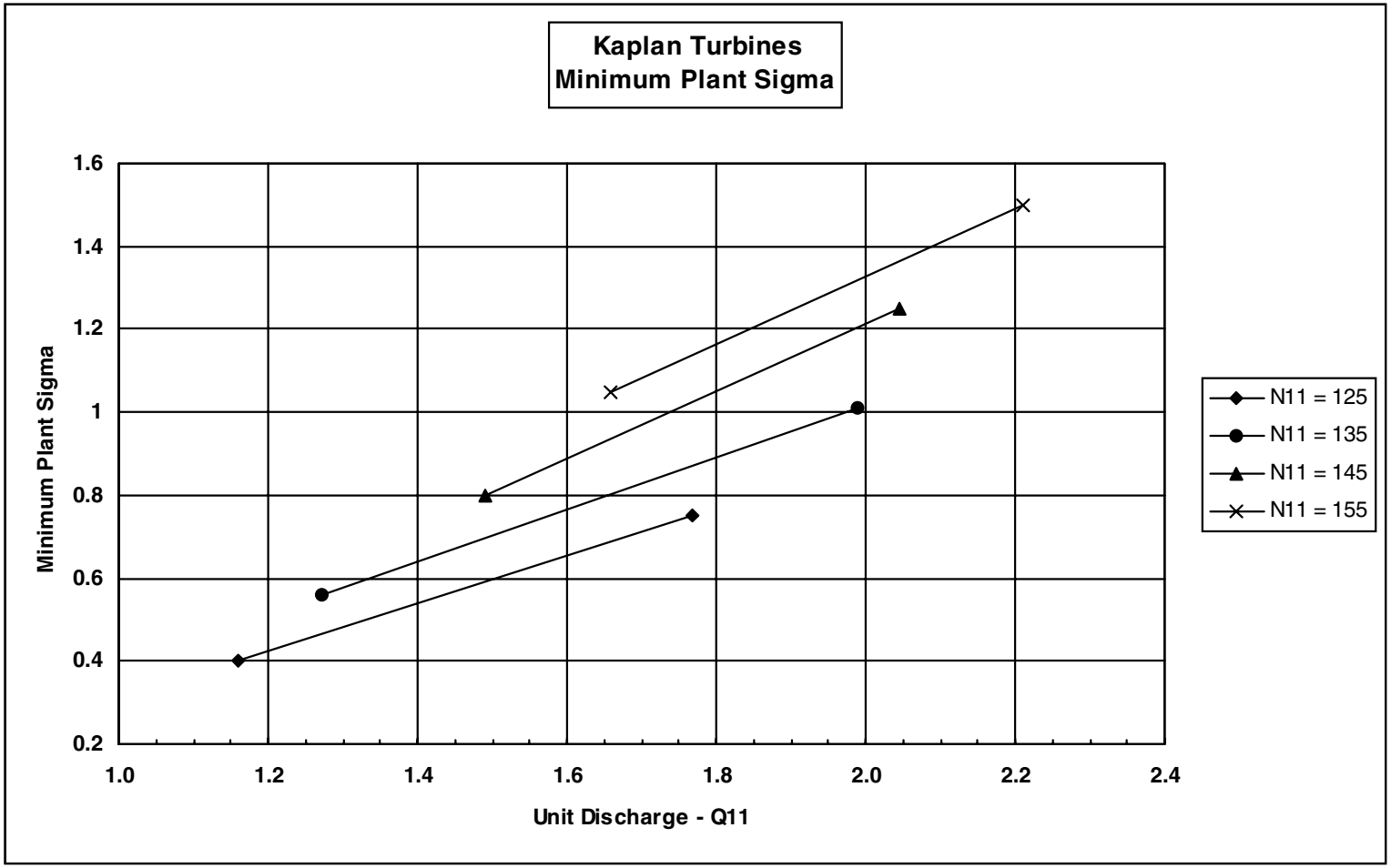

Figure 5-13
Kaplan Turbines - Minimum Plant Sigma

5.5.4 Pelton Runner Upgrade

The possible increases in efficiency and/or power for a Pelton runner upgrade can also be estimated using a similar approach as discussed in Section 5.5.2 for a Francis runner upgrade. The peak efficiency of a modern Pelton turbine is shown on Figure 5-14, and typical breakdown of losses is shown in Table 5-10:

Table 5-10
Breakdown of Losses in a Pelton Unit

Component	Low Head Horizontal	High Head Multi – Jet
Intake piping and injectors	10%	8%
Runner	80%	84%
Housing	10%	8%

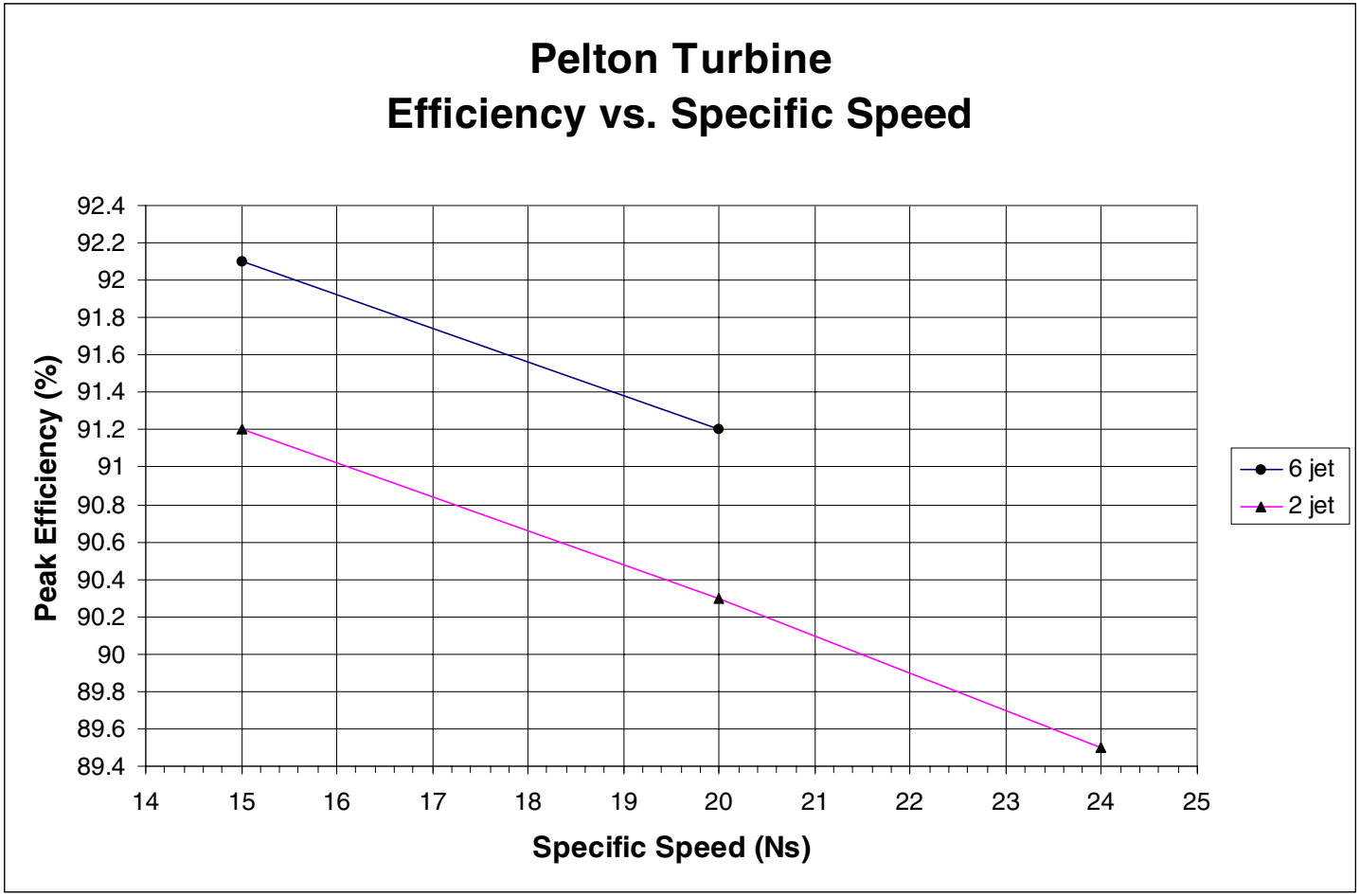

Figure 5-14
Peak Efficiency of Pelton Turbines

- To estimate the upgrade potential of a Pelton turbine, the dimensions of the existing turbine in comparison to a modern design with the same rotational speed and similar design parameters should be given. This may be estimated from various published literature. The formulae below are taken primarily from "Modern Trends in Selecting and Designing Pelton Turbines" by F. de Siervo and A. Lugaresi.[29]

Given parameters of existing unit:

- head (H)
- power (P)
- speed (n)
- number of jets (i)

Calculate the distributor pipe and housing dimensions for a new modern turbine:

- Specific speed per jet (N_s) = $\frac{n(P/i)^{0.5}}{H^{1.25}}$ [5-35]
- Velocity ratio (Ø) = $0.5445 - 0.0039\ N_s$ [5-36]
- Runner pitch diameter (D_2) = $\frac{84.5 \varnothing H^{0.5}}{n}$ [5-37]
- Runner outer diameter (D_3) - based on an "experience curve" = $D_2\ (1.028+0.0137\ N_s)$ [5-38]
- Jet diameter (d) = $\frac{(P/i)^{0.5}}{5.4H^{0.75}}$ [5-39]
- Distributor entrance (or inlet pipe) diameter (A) = $\left(\frac{P}{5.56H + 2.43H^{1.5}}\right)^{0.5}$ [5-40]
- Vertical shaft turbine
  - Pit diameter (L) = $0.78 + 2.06\ D_3$ [5-41]
  - Pit height (centerline of runner to top of pit) (G) = $0.196 + 0.376\ D_3$ [5-42]
- Horizontal shaft turbine
  - Pit width (W) = $13\ d$ [5-43]
  - Pit length from shaft centerline to downstream end (F) = $1.7\ D_2$ [5-44]

[29] F. de Siervo and a. Lugaresi, "*Modern Trends in Selecting and Designing Pelton Turbines*", Water Power and Dam Construction, Decmeber 1978, pp. 40-48.

(a) Efficiency Increase

An initial estimate of efficiency of an upgraded turbine with the same full load flow as the existing turbine can be estimated as follows:

1. Determine the full load flow of the existing turbine (Q_{fl1}) at design head, either from site test data or calculating the flow from the nameplate data, assuming a full load turbine efficiency of 88 percent.

2. From Figure 5-14 determine the efficiency (E_{pi}) of a completely new turbine with the same specific speed. Efficiency will generally increase with increasing number of jets and decrease with increasing specific speed per jet.

3. If the diameter of the distributor pipe (A_e) is smaller than that for the new turbine (A_i), adjust the efficiency by the following:

$$\Delta Eff_{\ 1} = [1 - (A_i/A_e)^5\ ] \times 0.9\% \qquad [5\text{-}45]$$

4. If the product of the pit diameter and the pit height ($P_e = L \times G$) for vertical units or the product of pit length and pit width ($P_e = W \times F$) for horizontal units is less than the corresponding values for the new turbine (P_i), adjust the efficiency by the following:

$$[1 - (P_i/P_e)^2] \times 0.9\% \qquad [5\text{-}46]$$

5. If the turbine has external needle servomotors, decrease the efficiency as follows:

$$\Delta Eff_{\ 3} = -0.3\%$$

6. Calculate effective model efficiency (E_p)

$$E_p = E_{pi} + \Delta Eff_{\ 1} + \Delta Eff_{\ 2} + \Delta Eff_{\ 3} \qquad [5\text{-}47]$$

(b) Power Increase

The maximum turbine power can be estimated based on the upper limit to specific speed, from the formula:

$$N_s = 26 - 0.0223\ H + 3.37 \times 10^{-5}\ H^2 - 2.03 \times 10^{-8} H^3 \qquad [5\text{-}48]$$

The upper limit is set to ensure cavitation free operation. For six jet Pelton turbines, the specific speed should also be less than or equal to 20 to avoid an excessive drop off in efficiency at full load.

Once full load power is established, full load flow ($Q_{fl\ 2}$) can be calculated, assuming a turbine efficiency of 88%. The peak efficiency can be estimated from Figure 5-14 and the actual efficiency estimated using the method described in (a) above.

A modern runner designed to the present hydraulic parameters will often require a slightly different pitch diameter. On single jet horizontal units, this can be accomplished by raising or lowering the generator. In come cases, it is possible to realign the nozzle to the new pitch diameter.

(c) Runner and Bucket Sizing

For a specified range of operational heads and loading conditions, a supplier can determine the bucket sizing that will provide the best overall performance. The turbine designer can optimize the bucket size for any one turbine operating condition. However, since most Pelton turbines are required to operate at a variety of load conditions any design will be a compromise from the one optimized operating point. Most modern runner designs optimize on a bucket width to jet diameter ratio which is selected, depending on the number of jets and specific speed. The bucket optimization process is further complicated by the requirement of seasonally affected loading, the ability to block load, and changes in power pricing.

5.5.5 Pump-Turbine Runner Upgrade

Many reversible pump-turbine installations were designed in the 1950's and 1960's when pump-turbine technology was not well established. As a result, when applying modern design techniques, there is room for performance enhancement and increases in efficiency, turbine power and pump flow are possible with runner upgrade on pump-turbines. However, for a reversible pump-turbine, pump and turbine characteristics are closely related and the design is typically a compromise between the two modes of operation. A primary reason for this is that for a given runner the turbine best efficiency head is higher than the pump's best efficiency head; however at almost all plants, because of the effect of head losses, pump "net" (total dynamic) head is higher than turbine net head. With runner upgrade, modifications to improve performance in one mode will affect the performance in the other mode. Selection of the optimum upgrade may be a tradeoff of different performance characteristics. Other limitations may influence the runner upgrade. For example, maximum allowable pump-input, which occurs at the minimum head/maximum flow point, may be restricted by the capacity of the motor-generator.

The peak model efficiency for a modern reversible pump-turbine is shown on Figure 5-15. As mentioned for Francis and Kaplan turbines, these efficiency levels cannot be reached by only replacing the runner, as other pump-turbine components affect efficiency. The breakdown in losses between the various components is similar to that for a medium to high head (medium to low specific speed) Francis turbine. The losses in the runner usually make up about 40% of the total pump or turbine losses.

Examples of pump-turbine performance increases based on model test results are shown on Table 5-11.[30] These can be used as a guide to estimate potential performance increases with runner upgrade.

Table 5-11
Pump-Turbine Runner Upgrade[31]

	High Head	Medium Head	Low Head
Pump Specific Speed N_Q	30	45	90
Year of initial installation	1965	1967	1961(2)
Increase in efficiency (%)			
- pump	2	2.5	2
- turbine	4	2	2.5
Increase in peak efficiency flow (%)			
- pump	16	1.5(1)	25
- turbine	15	2	30

Notes:
1. The flow increase for the medium head design was limited by the capacity of the motor-generator.
2. Second runner design installed in 1980.

[30] William H. Colwill and Selim A. Chacour, "*Best Pump/Best Turbine - The Trade-offs with Pump/Turbine Upgrades"*, Waterpower 1995.

[31] William H. Colwill and Selim A. Chacour, "*Best Pump/Best Turbine - The Trade-offs with Pump/Turbine Upgrades"*, Waterpower 1995.

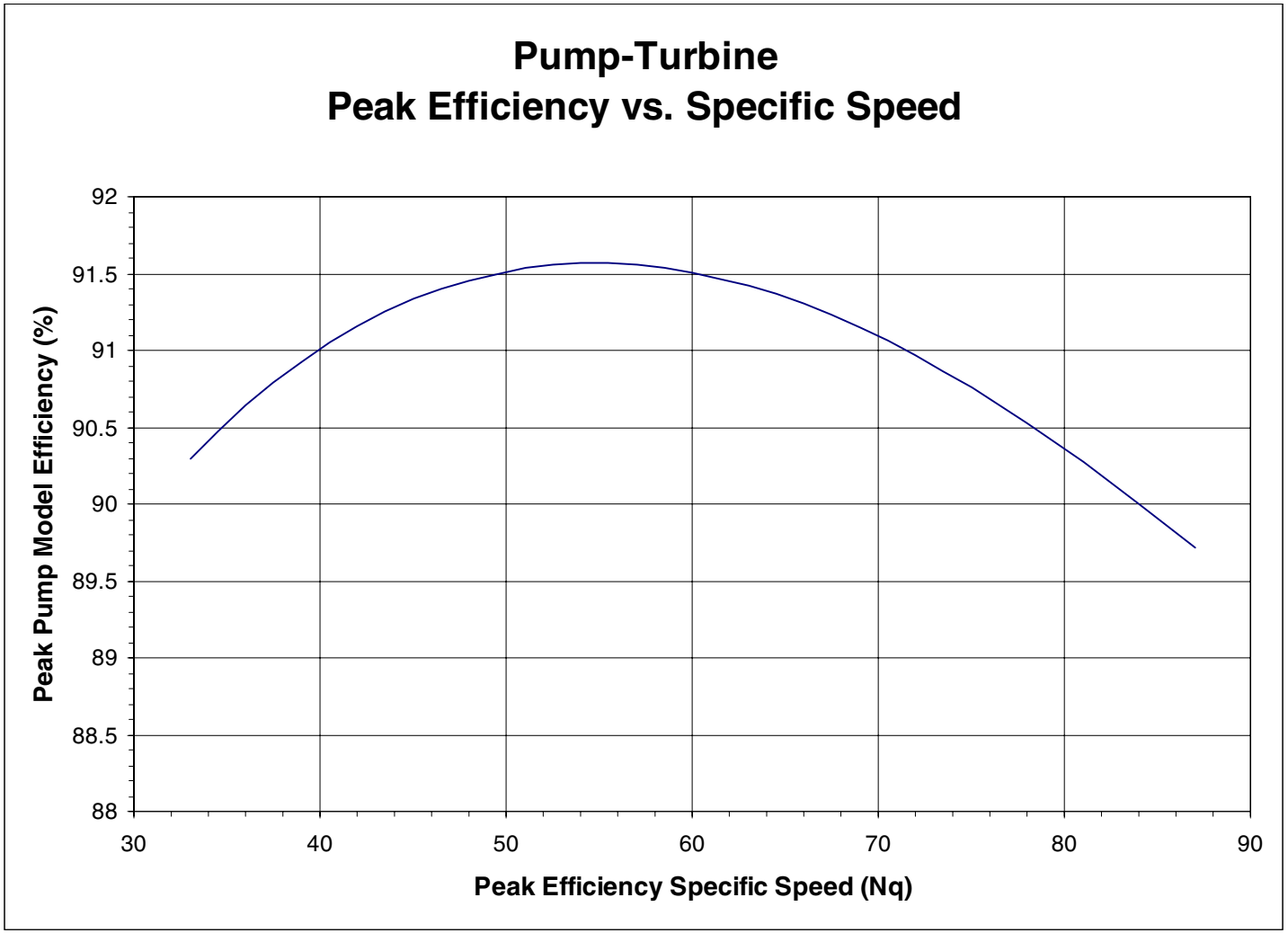

Figure 5-15
Pump-Turbine - Peak Efficiency vs Specific Speed

5.6 Replacement of Other Mechanical Equipment

Modernization Opportunities (Step 4-5, Volume 1)	**Benefits of Modernization (Step 4.5, Volume 1)**
Further Studies Required	
Impacts of Modernization on Other Equipment	**Other Equipment that Limits Modernization (Step 4-5, Volume 1)**
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

5.6.1 Wicket Gates and Wicket Gate Operating System

Self-lubricated wicket gate bushings should be considered when replacing bronze bushings. By eliminating high viscosity grease, reduced bushing clearances are possible which may lead to better governor control, reduced leakage and slight improvements in unit efficiency. See Section 5.2 for more details on developments in self-lubricating wicket gate bushings.

5.6.2 Pelton Nozzle Assemblies and Deflectors

Pelton turbine needle tips and nozzles may be replaced to provide increased flow as part of runner upgrade. At installations where the needle tips and nozzles suffer from erosion damage, ceramic or sprayed tungsten coatings can be considered.

Provision of a new governor with a higher pressure hydraulic system would require replacement of the servomotors for both the needles and the deflectors. New or modified servomotors would also be required if an increased needle stroke is required to provide increased turbine flow.

Replacement of an older nozzle assembly which has an external servomotor with a new nozzle assembly incorporating an internal servomotor is possible. However this may also necessitate modifications to the inlet piping.

Application of electric servomotors on Pelton turbines has been relatively difficult due to the fast deflector closing speed required in an emergency; this calls for a very large capacity servomotor.

5.6.3 Governing Systems

Governor upgrades are initiated because of:

- Lack of spare parts for the existing governor (obsolescence)
- Automation of the hydro plant requires it (modernization)

- Requirement to improve plant performance characteristics
- Need to improve environmental performance (oil leakage)

Existing governor systems are often a mechanically driven actuator and electrical control circuits utilizing solid state components driven mostly by analog signals. Speed regulation can be difficult in certain applications with unit "hunting" when interfacing with the automatic generation controllers. These systems can require extensive maintenance, and obsolescence of parts can be a problem.

Governor upgrades involve moving from mechanical or analogue electronic systems to a digital electronic system of speed sensing and control. New digital hydraulic actuator controllers can provide improved speed regulation, responsiveness and reliability. Automatic transfer from synchronous condensing to generation when low frequency is sensed may be possible with an upgraded control system. A hydraulic system is used to amplify the controller's signals and generally is replaced when the controller is replaced. The main valve supplied by the hydraulic system may, or may not be replaced in an upgrade scenario depending upon its condition and the economics of its replacement.

Modern governors tend to use high pressure hydraulic systems as opposed to the low pressure systems of the past. Consequently they have a reduced volume of oil and have better response characteristics. New servomotors also have improved response characteristics. The potential environmental problem of an oil spill is lessened with a reduced oil volume.

For more information on digital governor systems, see Sections 5.2.7 and 4.8 of this Volume.

5.6.4 Turbine Inlet Valve

The drivers for the upgrading of the Turbine Inlet Valve (TIV) are:

1. An uprated turbine creates higher head and flow conditions
2. Deterioration of the valve is severe and replacement is required.
3. The hydraulic and electric control system is unreliable, especially for emergency closure.
4. Significant leakage because of an outdated disk rotor seal design.

The modernization options are:

1. To install a valve with a lower head loss. Due to improvements in computer technology that enable the use of CFD and other numerical monitoring techniques, modern valves have lower head losses and improved fluid dynamic designs. Installing a valve with a reduced head loss can provide a proportionate increase in operating head and output. For example, replacing a butterfly valve with a flow-through butterfly design or spherical valve can reduce head loss. The head loss reduction can be determined from the equations provided in the following

subsection. Evaluating the costs of replacing the valve relative to the resulting benefits will determine the feasibility of replacement.

2. To install a valve with a more reliable control system. Replacing an existing hydraulic system with a newer system incorporating a counter-weight can improve the valve closure reliability. If there is insufficient space for a counterweight, a new hydraulic system with piston or bladder accumulators can be used to provide emergency closure. To improve environmental performance of the plant, one option for the TIV is to replace an oil hydraulic valve operating system with a water hydraulic system.

3. To install a valve with greater capacity. If the present valve cross-sectional area limits flow to the turbine or if turbine upgrading and increased flow are contemplated, replacing the inlet valve with a larger valve should be considered. The effective valve cross section should be equal to or greater than the turbine inlet cross section, or alternatively, the valve diameter can be selected by evaluating the potential head loss reduction.

4. Many older butterfly valves have metal-to-metal seals/seat. "Newer" designs would have rubber seals which provide more effective sealing. Rubber seals can also be considered for some lower head spherical valves.

Head Loss

A performance characteristics of inlet valves is the head loss or energy loss across the valve. Head loss attributed to the inlet valve can be measured by comparing the upstream and downstream pressures using a differential manometer at the rated unit discharge. Because of the relatively low head losses in valves, pressure measurements may not be justified for the level of accuracy required to proceed with modernization activities. Therefore the head loss may be estimated as described below.

Inlet valve head loss depends on the type of valve and the flow velocity. The valve diameter is selected so that the turbine inlet valve velocity is less than the velocity at the turbine inlet to avoid disturbing the flow to the turbine.

For butterfly valves, the net flow cross section area is selected to be greater than the area of the turbine inlet. If this area is less than the turbine inlet area, the valve may restrict flow to the turbine and replacement should be considered.

Head loss in butterfly valves can be calculated by the following formula:

$$h = k \times \frac{v^2}{2g}$$

where:

h = head loss, ft (m),
k = head loss coefficient (from Figures 5-16 and 5-17)

v = flow velocity ft (m/s) (calculated for nominal diameter), and
g = acceleration due to gravity, 32.2 ft/s^2 (9.81 m/s^2)

The head loss coefficient can be obtained from Figures 5-16 and 5-17, depending on the type of butterfly disk and disk geometry.

Figure 5-18 shows the pressure loss gradient across a butterfly valve assembly with upstream and downstream extensions.

The head loss due to spherical valves is essentially negligible and corresponds to the head loss of an equivalent unobstructed length of pipe. For the purpose of modernization studies, the head loss of spherical valves can be considered to be zero.

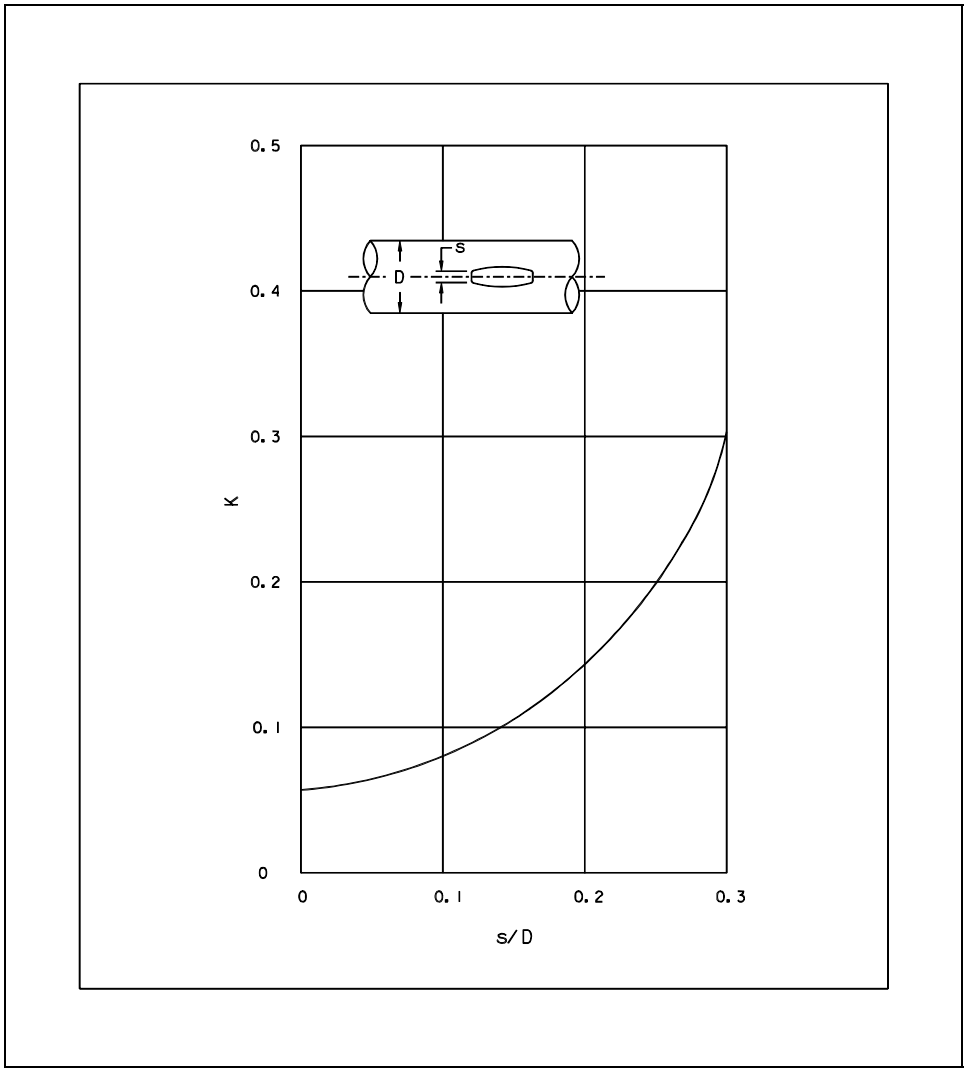

Figure 5-16
K-factor for Butterfly Valve with Lentil-Type Disk

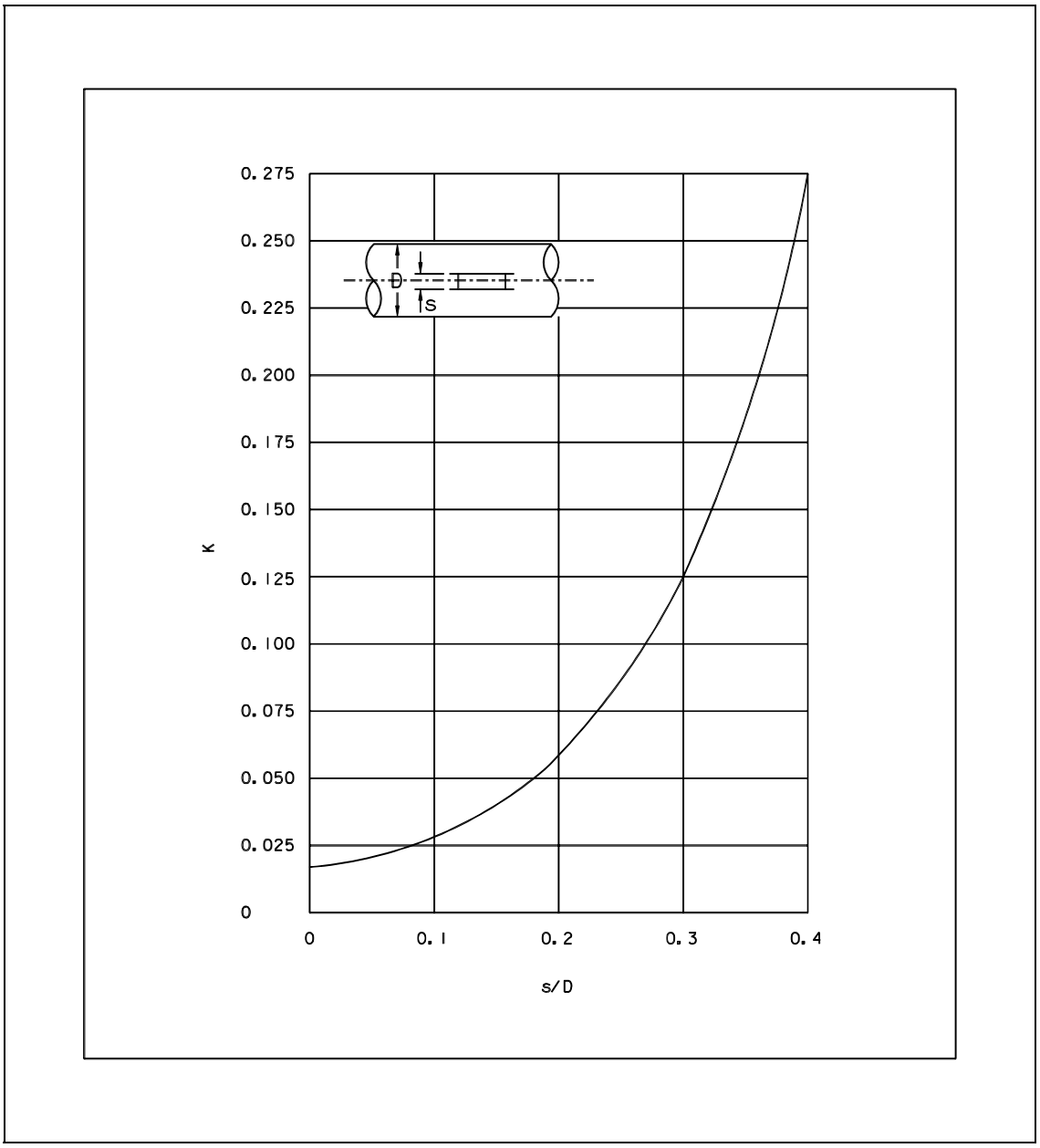

Figure 5-17
K-factor for Lattice or Biplane-Type Disk

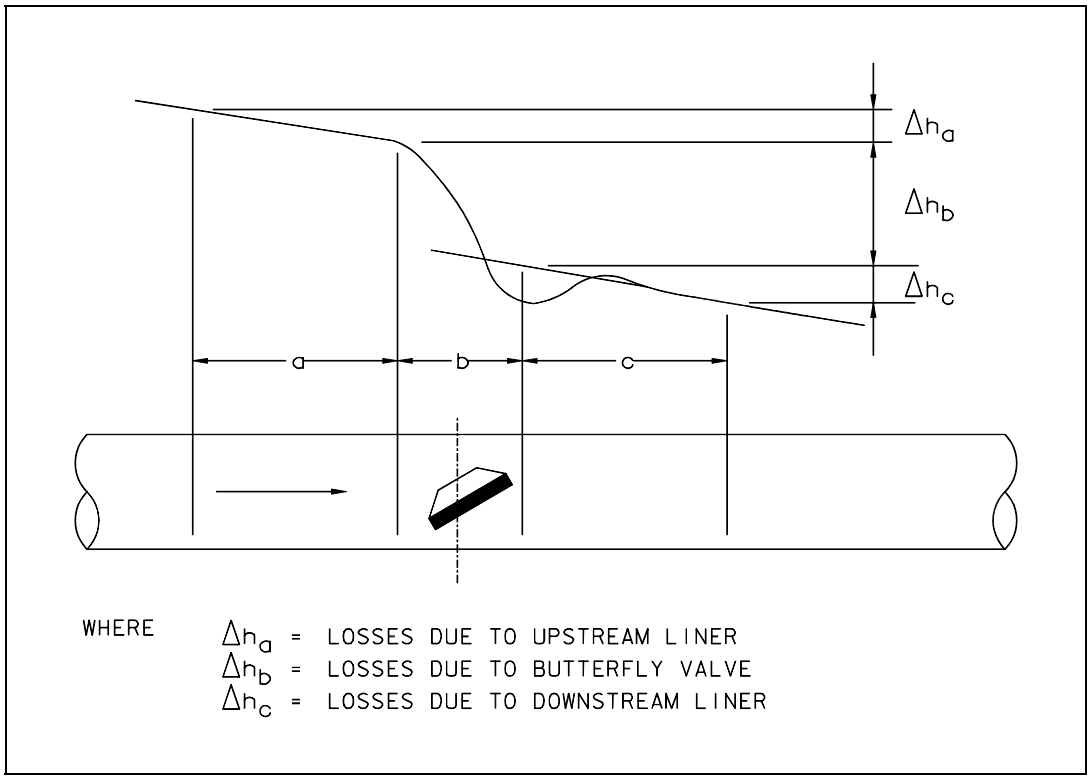

Figure 5-18
Pressure Loss Gradient Across Butterfly Valve Assembly

Valve Dimensions

The valve dimensions and space requirements for spherical and butterfly valves can be determined from Figure 5-19 and 5-20, respectively. The valve dimensions are provided as a function of the valve diameter, D.

Should the available powerhouse space requirements limit the inlet valve size, a cylindrical gate between the stay ring and wicket gates may be possible. However, a cylindrical gate is a very specialized case and will require the investigation of the available space between the turbine and generator and between the wicket gates and stay vanes. Such a concept would likely be unfeasible as part of a turbine modernization program.

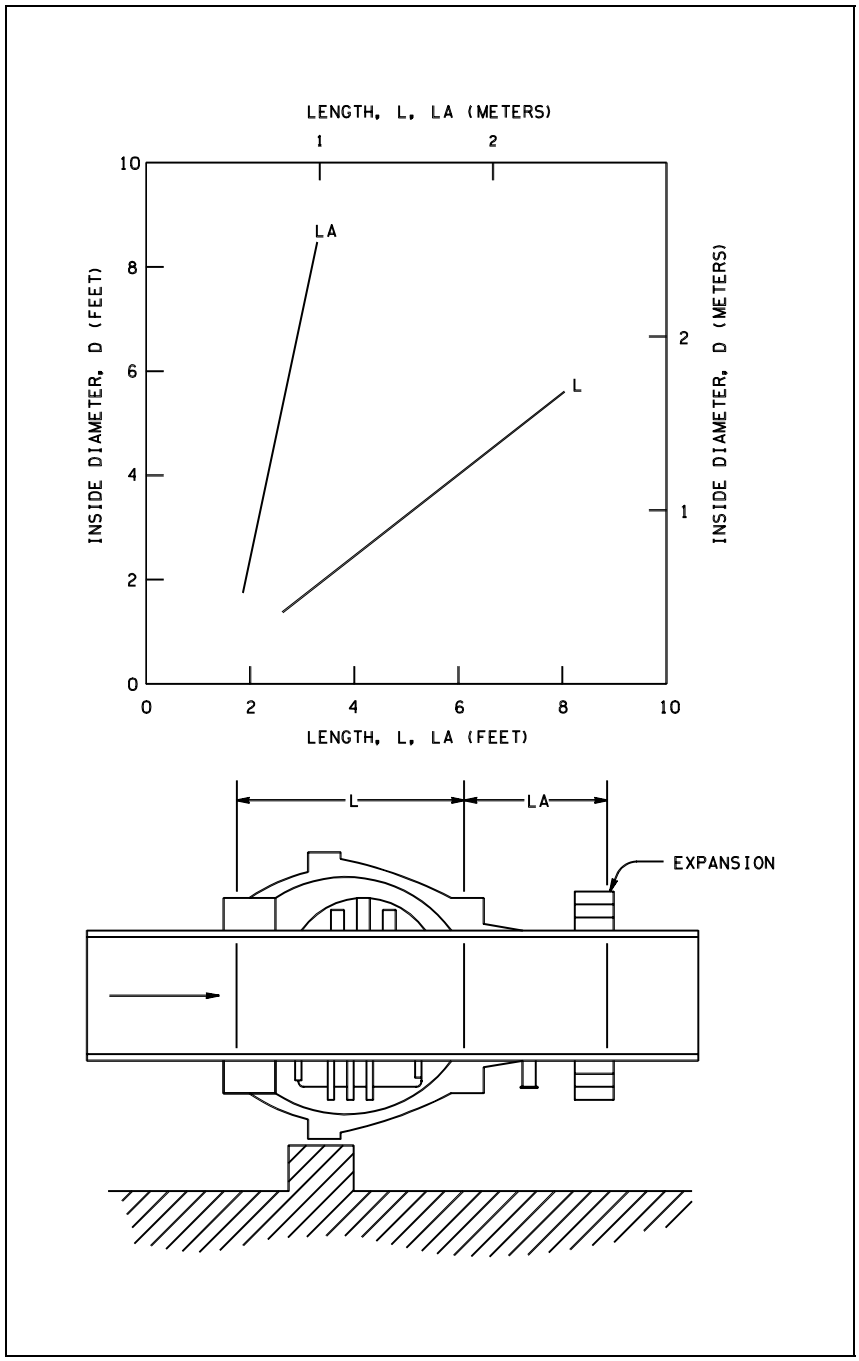

Figure 5-19
Main Dimensions of Spherical Valve

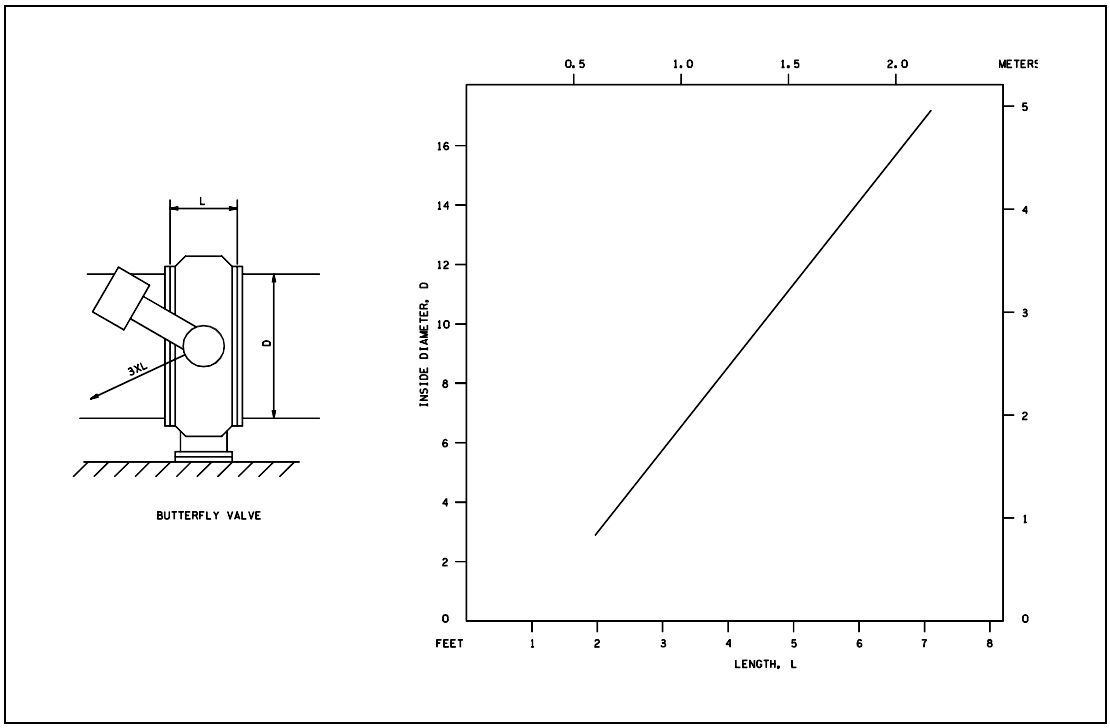

Figure 5-20
Main Dimensions of Butterfly Valve

5.7 Effects of Increased Discharge on other Plant Components

Modernization Opportunities	**Benefits of Modernization (Step 4-5, Volume 1)**
Further Studies Required	
Impacts of Modernization on Other Equipment (Step 4-5, Volume 1)	**Other Equipment that Limits Modernization (Step 4-5, Volume 1)**
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

Table 5-12 lists the trashrack and other turbine components which are affected by an increase in capacity and the potential problems that can occur with the resultant increase in flows. Table 5-12 also outlines the probability of occurrence, possible remedies, and the difficulty in implementing the remedy.

For potential problems which have a low probability of occurrence and can be resolved with medium or low effort, preventive action may be postponed until runner upgrading is completed and the actual problem is known.

Table 5-12 shows that increased discharge influences upstream pressure rise and wicket gate torque, and that increased power influences turbine shaft torque. If the resultant operating stress

exceeds the allowable stress limit, the gate operating mechanism or turbine shaft may have to be replaced. In many cases, however, the increased stress level will be acceptable, but needs to be confirmed in advance.

5.7.1 Pressure Rise

As a first approximation, hydrodynamic phenomena are proportional to the flow velocities. Therefore, if all other parameters remain unchanged, the percentage of increase in spiral case and penstock pressure rise can be estimated to be equal to the percentage increase in maximum flow. The same relation can be used to estimate the maximum surge in simple shaft type surge tanks. For other types of surge tanks, the changes will generally be smaller, but require special analysis, which is beyond the scope of these Guidelines. This simple check can be used to determine if the increase flow rate can be accommodated by the water conveyance system.

For example, if the existing flow in a penstock is 1000 cfs (35 m^3/s) and the pressure rise is 30%, the pressure rise for 1200 cfs (42 m^3/s), a 20% increase, will be about 36% (30 + 20% of 30).

Table 5-12
Trashrack and Other Turbine Components

Affected Component	Affecting Reason	Potential Problems	Probability of Occurrence	Remedy	Implementation Difficulty
Trashrack	Higher discharge	Increased excitation frequency and response with other natural frequencies.	Low	Welding or more stiffeners between trashrack bars.	Easy if easy to remove
Spiral Case	Higher discharge	Excessive increase in pressure rise during shutdown.	Low	Change wicket gate closing time.	Easy/Medium
Stay Vanes	Higher discharge	Excessive hydrodynamic forces. Excessive excitation frequency and resonance with natural frequencies.	Low Low	Increase vane thickness. Damping plate welded between the vanes. Modify profile, etc.	Very Difficult Medium
Wicket Gates	Higher discharge	Excessive hydrodynamic forces Excessive higher torque. Increased excitation frequency and resonance with natural frequencies.	Low Medium Low	Increase wicket gate's thickness. Increase gate operating mechanism and/or servomotor capacity. Modify trailing edge.	Difficult Difficult Medium
Turbine Shaft	Higher output	Excessive torque.	Low	New shaft having higher strength material.	Difficult
Thrust Bearing	Higher discharge	Excessive axial thrust.	Low	Change diameter of runner wearing ring.	Difficult
Draft Tube	Higher discharge	Excessive hydrodynamic forces.	Low	See "Reduce Runner Vibration" subsection.	Medium
Turbine Inlet Valve	Higher discharge Higher head	Operating forces exceed capacity of actuator operating system; valve components overstressed	Low	Replace actuator operating system and/or valve	Medium
Turbine Inlet Valve	Higher discharge	Unable to close against max flow	Medium	Modify/replace closing mechanism	Difficult

Penstock pressure rise and surges can be reduced by increasing the wicket gate closing and opening times. However, this will cause a higher overspeed in the event of unit load rejection. Overspeed is approximately proportional to the square root of closing time divided by the water starting time of the unit. A rough estimate of the change in overspeed can be calculated as half the sum of the percentage increases for power and closing time.

For example, if an existing 50 MW unit has a 30% overspeed for a 10 second wicket gate closing time, uprating to 60 MW (20% power increase) and changing the closing time to 12 seconds (20% increase), will result in an overspeed of approximately 36%, as follows:

$$30\% \; x\left(1+\left(\frac{20+20}{100x2}\right)\right)=36\%$$

As a general precaution, however, a detailed transient analysis should be conducted if the full load existing unit overspeed at shutdown is more than 50% of rated speed.

Surge tanks are often relatively insensitive to wicket gate timing. A substantial increase in closure time may be necessary to prevent surges.

5.7.2 Turbine Inlet Valve

If the existing valve is to be used with an upgraded turbine having higher flow and head, the operating forces may increase above the capacity of the operating system. Evaluation of the operating system by the valve manufacturer or a consultant should be performed to confirm that the valve components are not overstressed. Emergency closure criteria in particular should be evaluated for the new head and flow conditions. Section 4 of this Volume contains information on assessing valve condition and head losses.

5.7.3 Wicket Gate Torque

Generally, at large gate openings, the wicket gate hydraulic torque decreases as the wicket opening is increased; however, this should be verified by measurements. The wicket gate torque of the existing unit can be determined by measuring the differential servomotor pressure during closing and opening of the wicket gates. The wicket gate torque at larger gate positions can be estimated by extrapolating the curve to the maximum opening.

If the maximum servomotor pressure required to provide enough wicket gate torque for the upgraded runner does not exceed the hydraulic system design pressure, it is unlikely that upgrading will result in any problems. If the maximum servomotor pressure required exceeds the servomotor design pressure, either the entire hydraulic pressure supply system, including the servomotors, must be replaced with a higher pressure system, or a new servomotor with increased diameter provided. An expert should be consulted to evaluate necessary modifications.

5.7.4 Turbine/Generator Shaft

If the existing shaft capability cannot support runner upgrading, a new shaft having a larger diameter would be required, and consequently, new bearing(s) and a new shaft seal. To minimize the cost in this case, a new shaft with the same dimensions but higher strength material may be a solution; however, limiting the maximum upgraded capacity to the maximum capability of the existing shaft will likely be more cost-effective.

Section 5.4.6 provides a discussion on shaft design limits and torques/power.

5.7.5 Turbine Runaway Speed

With turbine modernization, the runaway speed is always a consideration. If the existing runner is being retained and higher capacity achieved with increased wicket gate opening, some increase in runaway speed is possible, but it will likely be very small. For Kaplan turbines, the runaway speed will not change if the existing runner is retained and the increase in turbine capacity is achieved through a greater runner blade opening.

For Francis turbines, runaway speed increases with increased specific speed. The diagram in Figure 5-21 can be used to estimate the relationship between runaway speed and synchronous speed as a function of specific speed. Specific speed is calculated by the following power based specific speed formula:

$$N_s = \frac{nP^{0.5}}{H^{1.25}}$$

where

H	=	rated head, ft (m)
P	=	power, hp (kW)
n	=	speed, rpm

Maximum runaway speed will occur at the maximum possible net head which may be different than the maximum net head for steady-state turbine operation. A conservative approach often used is to calculate the maximum runaway speed at the maximum gross head, which is calculated as follows:

$$H_{max\ gross} = HW_{max} - TW_{min}$$

where:

H_{max}	=	maximum gross head, ft. (m)
HW_{max}	=	maximum headwater level, ft. (m)
TW_{min}	=	minimum tailwater level, ft. (m)

Therefore, the maximum runaway speed is calculated as follows:

$$n_{R,max} = n\ (n_{R/n})\ \left(\frac{H_{max\ gross}}{H_r}\right)^{0.5}$$

where:

$n_{R,max}$ = maximum runaway speed, rpm,
$n_{R/n}$ = runaway speed/synchronous speed at rated head (Figure 5-21), and
n = turbine synchronous speed, rpm

An increase in runaway speed can cause the following problems:

- Increased generator rotor stresses.
- Runaway speed could reach the critical speed of the rotating parts.

Increased generator stresses are discussed in Volume 3. To confirm that the runaway speed remains below the critical speed of the rotating parts, the stress calculations of the existing generator should be revised or new calculations should be performed. For a given runner design, manufacturers can limit the runaway speed with some (usually small) compromise in performance. An increase of the blade inlet diameter at the crown will shift the peak efficiency head and reduce runaway speed. Adopting a "flat plate" rather than a fully airfoil blade design will also reduce runaway speed because efficiency will decrease more rapidly with departures from optimum head/speed.

The runaway speed of the upgraded runner should be specified, but cannot be confirmed precisely until model tests of the new runner are completed. In general, the runaway speed determined by model tests will be lower than the maximum values provided by Figure 5-21.

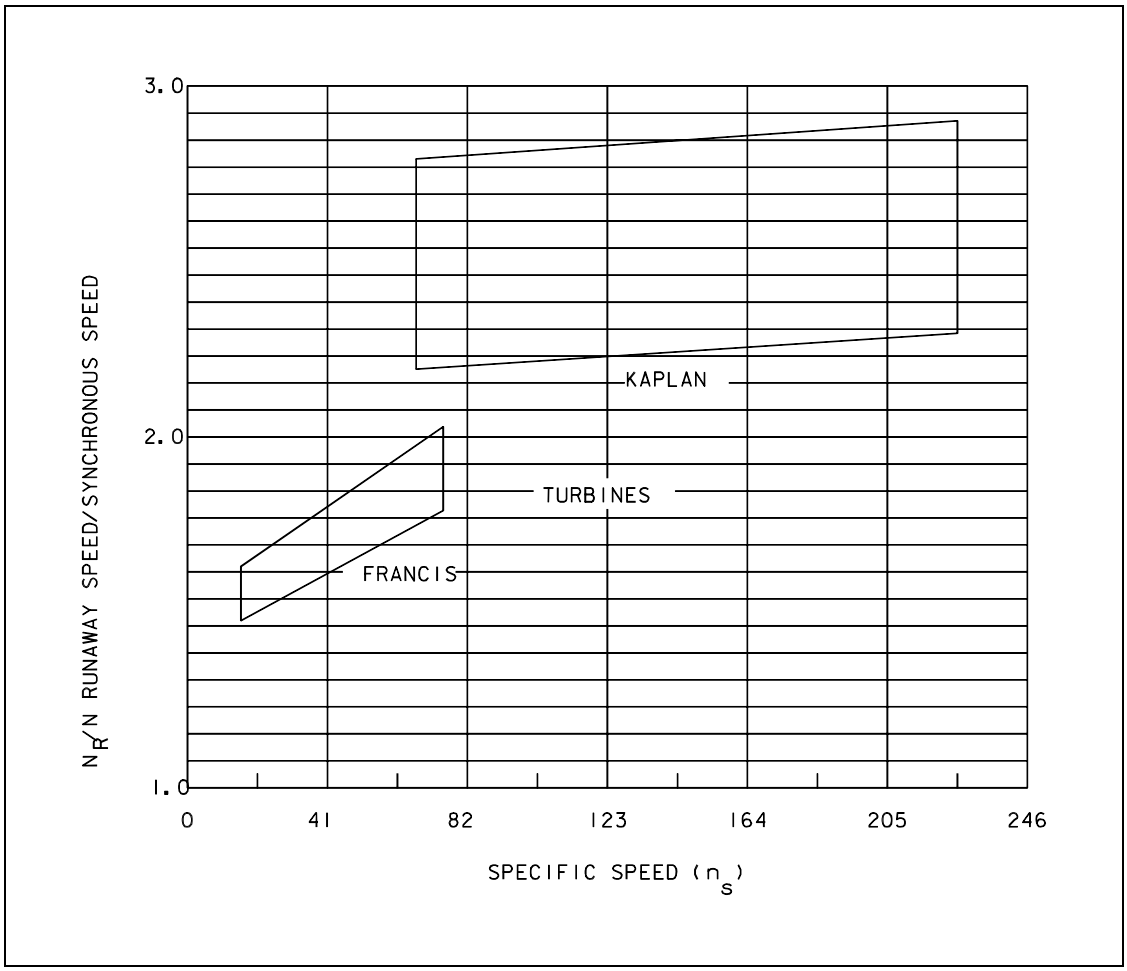

Figure 5-21
Ratio of Maximum Runaway Speed to Synchronous Speed versus Specific Speed

5.8 Chronic Plant Operating Problems

Modernization Opportunities (Step 5-2, 3, 4, 5, 6 Volume 1)	**Benefits of Modernization (Step 4-5, Volume 1)**
Further Studies Required	
Impacts of Modernization on Other Equipment	Other Equipment that Limits Modernization
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

Many plants have chronic operating problems, often necessitating restrictions on operating ranges or modes, which have been in place since the time of commissioning. Measures that are implemented years later to mitigate these problems are considered upgrades for the purposes of these Guidelines since they improve plant operation beyond historical levels.

Chronic plant operating problems specifically related to hydromechanical equipment may include:

1. excessive cavitation and/or erosion (Section 5.8.1)
2. excessive vibration levels and hydraulic pressure pulsations at certain zones (Section 5.8.2)
3. chronic runner cracking (Section 5.8.3).

5.8.1 Excess Erosion and/or Cavitation Damage

Turbine runners and other hydraulic parts can be eroded by solids such as sand in water, or by cavitation. The visual difference between cavitation and particle erosion is described in Section 4. Runner damage can also result from chemical corrosion; however, since chemical corrosion seldom occurs, it will not be treated in these Guidelines. Chemical corrosion can be identified because it will affect all the turbine components of the same material in an equal way.

Sand erosion usually affects the wicket gates, stay vanes, head covers, bottom rings, Pelton turbine injector needle tips and nozzle seat rings and deflectors in addition to the runner. Often these components must be replaced/repaired using more wear resistant materials. Component replacement with more resistant materials only results in longer intervals between necessary repair work and, therefore, will not provide a permanent solution. Better sand removal mechanisms can be a solution as they address the cause of the problems. However, the capabilities of de-sanding equipment is limited particularly if the sediment particles are very small. Therefore, sand removal mechanisms may be impractical.

Redesign of the runner to lower the water velocity (combined velocity vectors) through the runner for a set unit speed is another option that can be investigated.

Runner cavitation can be reduced by the following methods:

- Modify the runner to minimize or eliminate the source of the problem.
- Upgrade the runner by overlaying the cavitated areas with materials with increased cavitation resistance.
- Replace the carbon steel runner with a new stainless steel runner.
- Replace the runner with a new design which has superior cavitation performance.
- Air injection into the runner area either by natural aspiration or using low pressure compressors (blowers).
- Change the tailwater level to provide more submergence.

Stainless steel overlay is usually successful in reducing cavitation to an acceptable level when the runner is mild steel, the head is below 200 feet, the "velocity" of erosion is low, and an increase in turbine capacity is not desired. In other cases, the cost of weld overlay and repairs should be evaluated against the advantages of a new stainless steel runner.

A preliminary assessment of the maximum power output of a new runner can be made using the methods presented in Section 5.5. A more detailed assessment may require expert advice.

Injection of air into the runner area either by natural aspiration or using low pressure compressors (blowers) is a possible method of reducing cavitation damage. The benefits of air injection, however, are somewhat questionable; and this approach should be discussed with the turbine manufacturer or a specialist engineer. Large quantities of air could reduce efficiency. Most successful use of air injection to reduce cavitation damage has been reported on propeller turbines.

5.8.2 Excessive Vibration Levels and Hydraulic Pressure Pulsations

Excessive vibration can cause failure of turbine components and turbine foundations as well as the powerhouse structure. The runner is not always the source of vibration as shown in Table 5-13. Even when unit vibrations are caused by the runner, other solutions are often less expensive than runner replacement. When runner replacement is determined to be the most feasible solution, however, increasing the turbine capacity should also be considered.

Table 5-13
Source and Cause of Excessive Vibrations and Hydraulic Pressure Pulsations

Source	Possible Causes	Remedies
Mechanical Vibration of the Rotor	Mechanical imbalance of the runner or rotor Shaft misalignment Oscillating hydraulic forces Eccentric magnetic pull of the generator Exciting forces in the labyrinth seal Oil-film instability of the bearings Seal rubs	Rebalance rotating parts Increase stiffness of the bearing brackets and/or foundation connections Change number of blades on upgraded runner Change stiffiness of vibrating component
Vibration of the Stay Vanes, Wicket Gates and Runner Blades	Vortex shedding at the trailing edge of the vanes (Karman vortex) Blade/gate interaction	Limit turbine operating range Modify shape of blade trailing edge Replace with new runner
Pressure Pulsations in the Water Passages	Runner blade cavitation Draft tube surge	Inject air between the runner and wicket gates Replace with new runner Inject air into the draft tube Draft tube fins

The following paragraphs provide criteria to determine whether vibrations are excessive or dangerous. In addition, vibration types, sources, mechanisms, and remedies are examined.

Determine if Vibration is "Excessive"

The amplitude of horizontal turbine vibration can be determined by maximum shaft displacement. An example of one standard for shaft runout is provided in Figure 5-22 but there are many opinions as to what is considered excessive runout, particularly after the unit has been running for a while and components have heated up. Section 4.4, Volume 1 provides a discussion on guide bearing clearance and runout measurements and acceptable vibration levels.

Vibration Sources and Remedies

As previously discussed, vibrations of hydraulic turbine generator units can come from a variety of sources. The major sources of vibration are:

- mechanical imbalance,
- runner blades,
- stay vanes, and
- hydraulic pressure pulsations

which are discussed in the following sections.

Mechanical Vibration

Mechanical vibrations are caused by a mechanical imbalance of the rotating components such as the generator rotor and turbine runner and can result in considerable damage to the bearings, wearing surfaces and the civil structure. The frequency of mechanical vibrations is equal or proportional to the turbine speed. All rotating parts need to be balanced since the runner is not the only possible source of the problem. If the critical speed of the rotor is not sufficiently separated from the turbine speed, rotor balancing will not be sufficient to reduce the vibrations. In this case, stiffness of the bearing brackets and/or foundation connections will also need to be increased.

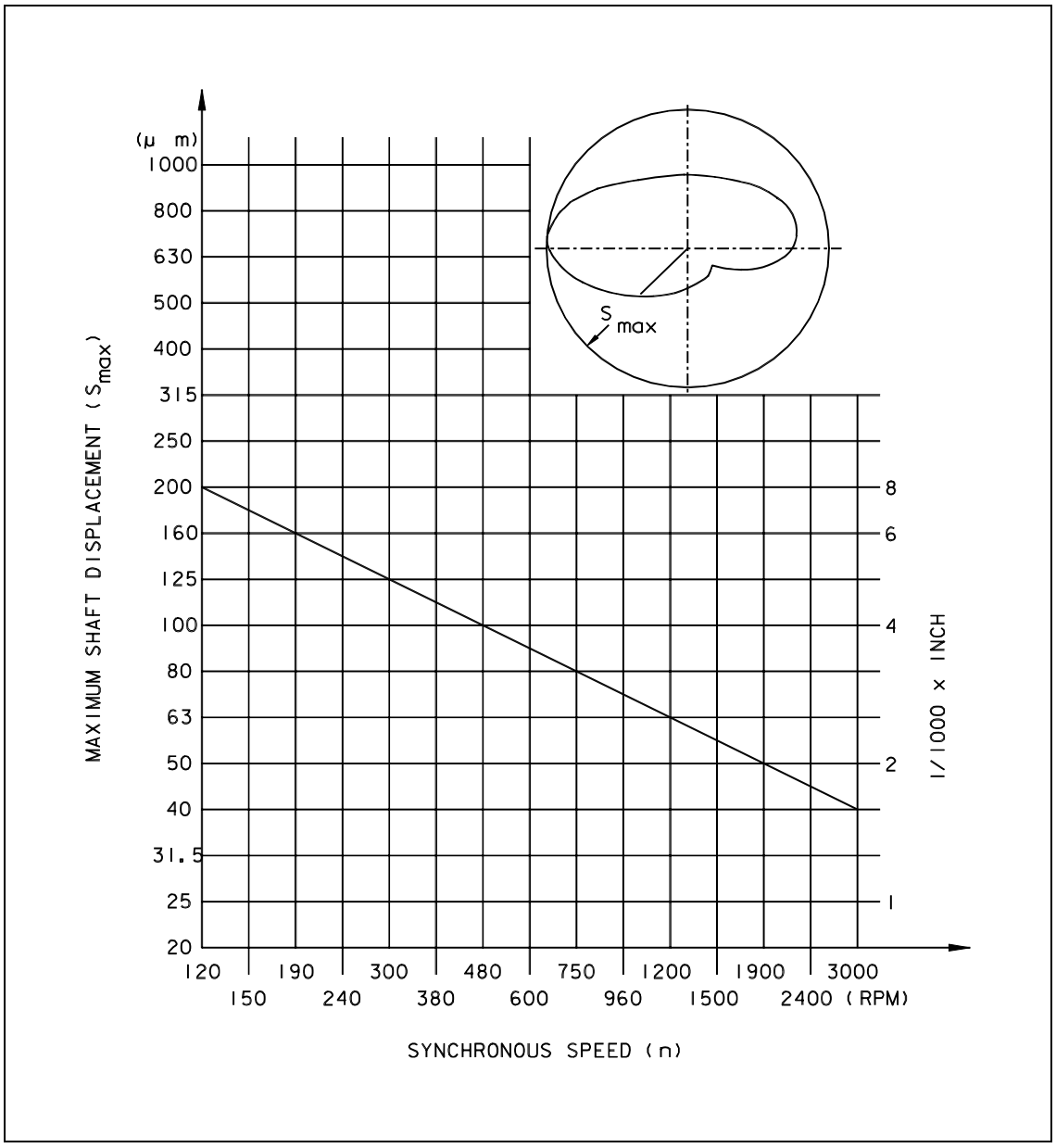

Figure 5-22
Hydraulic Turbine Shaft Vibration in the Normal Operating Range
Source: VDI 2059 Part 5. Reproduced with permission of VDI - Verlag GmbH.

Mechanical vibrations can also be caused by hydraulic oscillations. The number of wicket gates can cause an unequal flow distribution to the rotating runner blades resulting in oscillating forces on the runner. Table 5-14 lists the known forcing or exciting frequencies.[31]

[31] ASME Hydro Power Technical Committee, *The Guide to Hydropower Mechanical Design* HCI Publications, Kansas City, MO, 1996

The forcing frequencies may correspond to a natural frequency of the runner, leading to resonance problems. If resonance is a problem, the number of blades of the upgraded runner or the stiffness of the vibrating component should be changed to preclude resonance.

Table 5-14
Expected Frequencies in Hydro Equpment

Frequency (Hertz)	Remarks
RPS = RPM/60	One per Revolution
RPS/3.6	Rheingans number of 3.6 varies from 2.0 to 4.0 (could be as high as 8)
RPS x (Number of Runner Blades)	Hydraulic Forces from Runner Blades
RPS x (Number of Wicket Gates)	Hydraulic Forces from Gates
RPS x Runner Blades x Gates / *(Gates - Vanes)*	Interaction of Wicket Gates with Runner Blades
RPS x (Number of Bearing Pads)	Normally Noticeable in Shafting and Bearing Data
$\frac{a}{4L}n \quad \{ \begin{matrix} n = 2,4,6,... \\ n = 1,3,5,... \end{matrix}$ *where:* a = sonic velocity L = length	Natural Frequency of Pipe a/4L or a/2L Normally most predominant and can be estimated for very simple systems only
RPS x (Number of Generator Poles)	Generator Associated
RPS x (Number of Stator Slots)	Frequencies

Source: 'The Guide to Hydropower Mechanical Design', ASME Hydro Power Technical Committee. Published by HCI Publications, Kansas City, MO, 1996.
Web: www.hcipub.com. Used with permission.

Runner Blade Vibration

Cracks that occur near the trailing edge of the runner blades, hub or band after several years of operation may be caused by vibration of the blades. This type of vibration is the result of cyclical vortex shedding at the trailing edge of a runner blade. The repetitive cyclical forces have a frequency which is proportional to turbine discharge and inversely proportional to the thickness of the runner trailing edge. If this frequency coincides with one of the runner blade natural frequencies, severe vibrations can occur and result in runner blade cracks. This phenomenon is more prevalent on stay vanes than runner blades.

If blade vibration exists, the following remedies are possibilities that can be investigated:

- Limit the turbine operating range as a temporary measure.
- Reduce the excitation forces by modifying the shape of the blade trailing edge. Figure 5-23 shows one type of modification but an expert or the turbine manufacturer should be consulted before proceeding with any modification.

- Replace the runner with a new runner designed to increase the natural frequency of the blades in water.

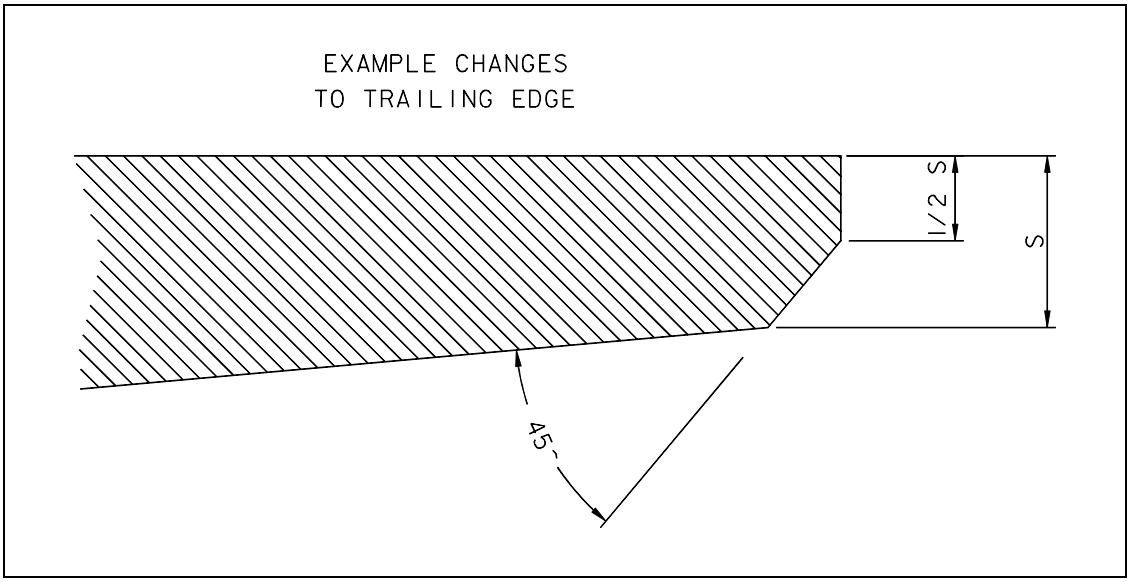

Figure 5-23
Recommended Trailing Edge Modification to Avoid Karman Vortex Excited Vibration

Vibrations caused by hydraulic pressure pulsations can be caused by severe runner cavitation or draft tube surging as discussed in the following.

Severe Runner Cavitation

Normally, cavitation causes metal removal and/or high frequency vibration and low amplitude noise. However, in exceptional cases, the cavitating area on the blades and the corresponding volume of gas reduce the natural frequency of the suction side water column and change the damping characteristics. As a result, the lower natural frequency may coincide with other frequencies and lead to a dangerous resonance condition at a certain output. Two remedies are possible:

- Inject air between the runner and wicket gates.
- Replace the runner with a new runner having improved cavitation behaviour.

The solution selected depends on whether cavitation erosion occurs in addition to vibration and whether the turbine setting is sufficient to eliminate cavitation at maximum discharge. For high head Francis turbines, compressed air injection requires high capacity air compressors which are large in size, have significant space requirements and are expensive to install and operate.

Draft Tube Surging

This phenomenon occurs at partload and overload conditions in Francis and fixed blade propeller turbines. As shown in Figure 5-24 the pulsation frequency is proportional to turbine load, which

can cause resonance problems at different outputs. This phenomenon can produce pressure pulsations in the draft tube and the penstock. Additionally, draft tube surge can cause discharge pulsations, and ultimately shaft torque and generator load swings. These pulsations can become dangerous and require the turbine operational range to be limited. Fortunately, many remedies are available.

One solution is a new runner design which has reduced pressure fluctuations. In recent years significant research through model testing has been done on runners with lower part load pressure fluctuations. However, some compromise in efficiency or power may be necessary.

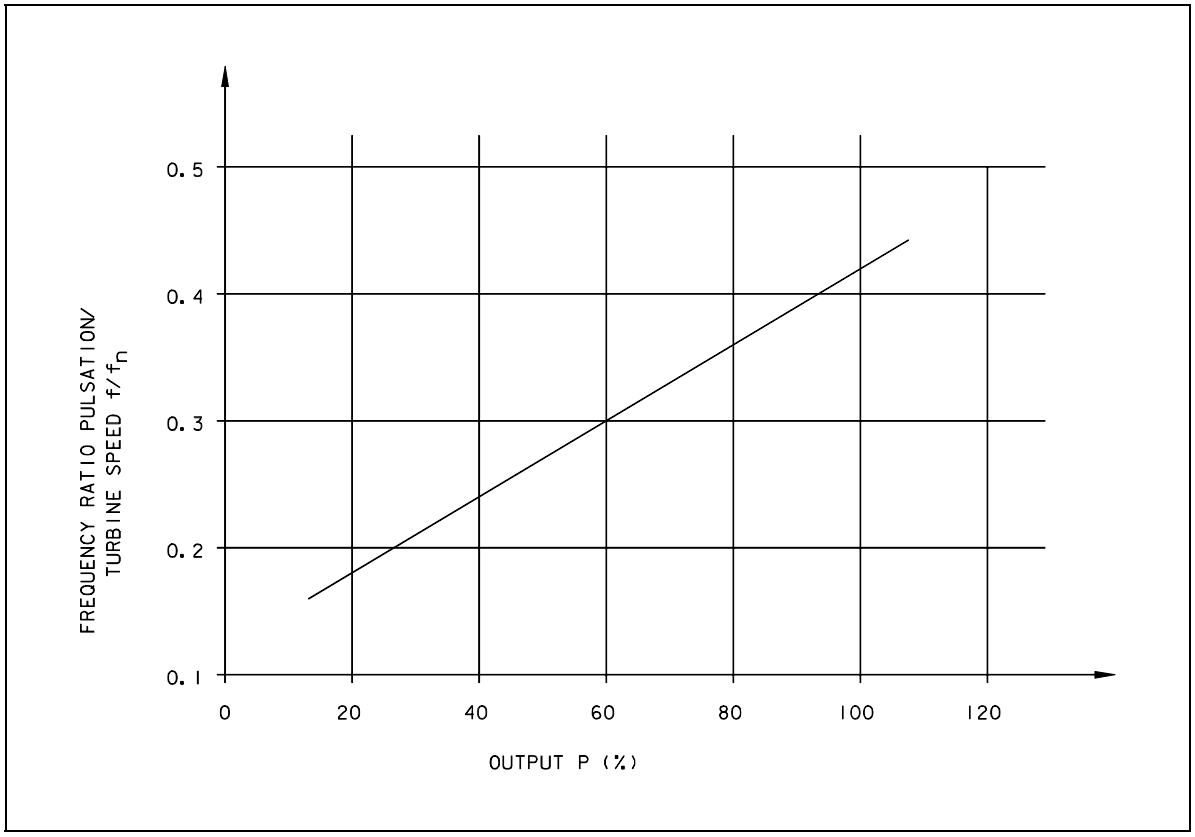

Figure 5-24
Frequency Ratio Draft Tube Pulsation to Turbine Speed Versus Output for a Francis Turbine

Another remedy is to inject air into the draft tube. A disadvantage of this method is that large quantities of air must be injected, which can reduce the turbine efficiency and requires expensive air compressors.

Draft tube fins (Figure 5-25) is one method of reducing surge. The fins reduce pulsations at part load without significantly affecting the efficiency. The fins do, however, transfer large forces to the draft tube walls due to the hydrodynamic forces acting on the fins and require a substantial connection. Additionally, since cavitation will occur, the fins must be fabricated from stainless steel, and the draft tube liner should be plated with stainless steel overlay in the vicinity of the fins. Draft tubes are covered in Volume 6 of these Guidelines.

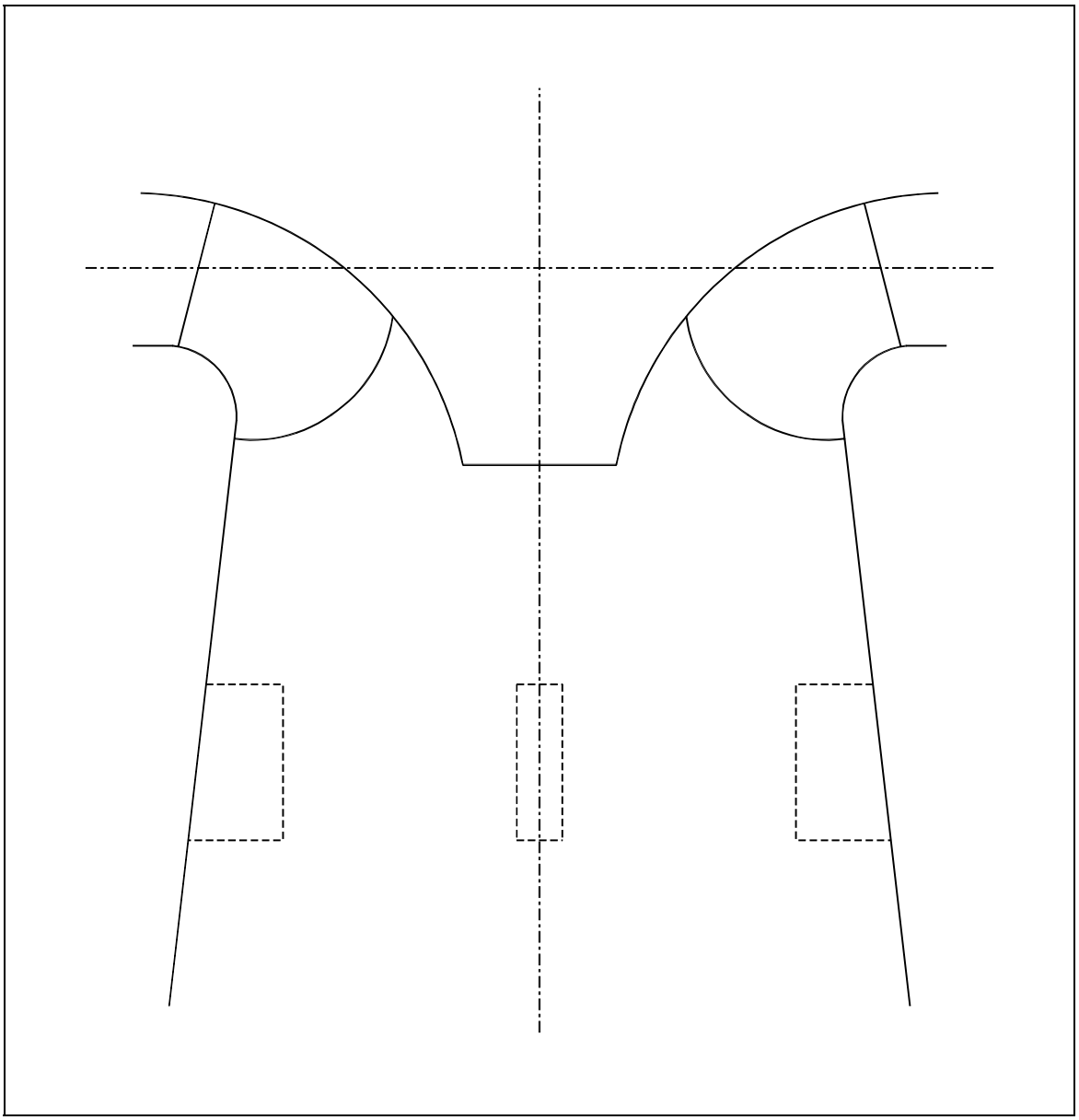

Figure 5-25
Stabilizing Fins Attached to the Draft Tube Liner of a Francis Turbine

5.8.3 Chronic Runner Cracking

The primary reasons for runner crack formation and propagation include:

- Poor design, such as blades that are too thin.
- Material defects, excessive and poor welding.
- Overstress under normal operation.
- Overstress under transient conditions such as runaway speed or shutdown.

- Fatigue cracks caused by vibration.

Runner cracks which occur during the guarantee period usually are caused by over-stress under normal operation; however, most runner cracks do not occur until the units have operated several years. While some cracks propagate because of material fatigue due to cyclical stresses, other cracks may have formed due to changes in operating conditions. For example, the operating head and load range may change, or governor failure could cause runaway and the runner stresses would exceed previous stress levels.

The following runner modifications are possible remedies to eliminate runner cracking and should be investigated:

- Machine a large radius at the blade to band or crown connections and polish the rounded groove to a smooth, shining surface to prevent stress concentrations.
- Apply several layers of water-resistant paint to prevent water contact with the runner material (fatigue strength of some runner materials is lower in water than in air).
- Modify the trailing edge of the blades to reduce the effect of Karman vortices and pressure pulsations (see Figure 5-23).

A new runner manufactured of a higher quality material should also be considered. As with all runner replacements, the efficiency improvements discussed in this section should be evaluated.

5.9 Development of Overall Plant Modernization Alternatives

<table>
<tr><td>Modernization Opportunities
(Step 5-2, 3, 4, 5, 6 Volume 1)</td><td rowspan="2">Benefits of Modernization
(Step 5-2, 6, 7, 8 Volume 1)</td></tr>
<tr><td>Further Studies Required</td></tr>
<tr><td>Impacts of Modernization on Other Equipment</td><td>Other Equipment that Limits Modernization</td></tr>
<tr><td>Timing of Modernization</td><td>Risk Evaluation of Modernization</td></tr>
<tr><td colspan="2">Modernization Opportunities Selected for Input into Table 4-6, Volume 1</td></tr>
</table>

5.9.1 Introduction

This volume has focused on hydromechanical equipment. A hydro plant, however, is composed of far more than only hydromechanical equipment. This section assists the user to determine the effects on the entire plant of modernizing hydromechanical equipment.

5.9.2 Developing Modernization Plans

Modernization plans generally increase plant capacity. Where feasible, capacity increases can be accomplished by increasing component capability, operating head, flow rate, and/or overall efficiency.

Since plant components often have different ratings or design margins, the capability of each component in the plant must be considered before uprating the component and plant capacities. Therefore, alternative uprating plans differ in the number of components for which uprating is required. The higher the uprating capacity, the more components affected, with proportionally higher costs.

The design criteria which determine the capability of electrical components, such as the generator, switchgear, transformer, and transmission line, are the apparent output or apparent capacity in KVA and not the active capacity measured in kW used to denote unit and plant capacity. Power factor (cos Φ) is used to convert between apparent and active capacity where KVA x cos Φ = kW. The power factor relationship determines the capability of the equipment to generate, transform, or transmit reactive power in addition to active power to meet the grid system requirements.

Older hydro plants were often developed in remote locations and connected to load centers by long transmission lines which required relatively high reactive power. Consequently, the rated power factors for old hydro generators are often relatively low and are in the range of 0.85 to 0.75.

Today's electrical grid system is different, and the need to generate and transmit reactive power from the hydro plant may be much lower than at the time when the plant was originally built. Therefore, the power factor requirement of the plant should be investigated in conjunction with modernization and updated if possible. Subsequent modernization plans should then be based on the updated power factor in calculating electrical equipment active power (MW). Quite often, limiting the power factor range to 0.90 to 0.95 can allow a 10 to 20% increase in active power capacity of the electrical equipment without modification.

Two different approaches can be used in developing realistic plans to uprate a plant: eliminating bottlenecks and evaluating the condition of critical plant components.

5.9.3 Uprating by Eliminating Bottlenecks

Eliminating bottlenecks, or limitations on a plant's output, considers the existing and uprating potential of the following major components which determine the plant capacity:

- Intake and trashrack
- Headrace canal or tunnel
- Penstock(s)
- Turbine(s)
- Tailrace canal or tunnel
- Generator(s)
- Transformer(s)
- Transmission lines

The cost of other affected components and auxiliaries such as the governor, valves, and switchgear would be added to the cost of the appropriate alternative. Usually, these costs are less significant than those for the major components.

Because of differences in design criteria between components, the uprating potential of a plant or a specific component typically occurs in steps which are not linear. Each specific component change results in an increase in plant potential which is independent of other components.

Some examples of step increases are a new runner that would increase the turbine capacity or a generator re-wind which would increase the generator capacity. Replacing the existing component with a component having a higher rating would achieve the maximum uprating potential but this is usually limited by space constraints imposed by the powerhouse or equipment.

In developing the initial uprating plans, the technical uprating options for each major component should be determined independently, neglecting cost considerations. The methods and information needed to determine the component uprating options are provided in Volumes 2 to 7 of these guidelines.

Tabulating the available options in a list as in Table 5-15 or in a diagram as in Figure 5-26 shows the interrelationship of the various alternatives and assists in identifying the optimal uprating plan. The bottleneck method can be demonstrated by Figure 5-27, which shows how uprating one component affects successive components. The existing capacity for each component is indicated in the bar graph. As shown, the existing plant capacity is "generator limited" to Level A because all other components have higher capabilities. Installation of a new stator winding would raise the generator capability above the existing turbine capacity. Achieving the maximum turbine capacity (Level B) would also require improvement of the intake and tailrace. The existing capabilities of the other components are sufficient to support operation at Level B.

Uprating the plant to Level C would require uprating the penstock by sandblasting and painting, rehabilitating the canal or tunnel, uprating the turbine with a new runner, uprating the generator with a new stator winding, core and exciter. Full use of a new turbine runner (Level D) would also require a new penstock.

Level E, the maximum uprating potential of the plant, is limited in this example by the maximum uprating potential of the tailrace. The tailwater could conceivably be limited in width by space conditions and in depth by turbine runner cavitation considerations under low flow. Uprating to Level E would also require lining the canal or tunnel.

Table 5-15
Uprating Options for Modernization Plans

Components	Existing Capacity Level (%)	Uprating Steps and Resulting Capacity Level Increase			
		Level 1	Level 2	Level 3	Level 4
Turbine	110	New runner, rest of turbine unchanged, capacity level 125%	New turbine, same speed as existing one; capacity level 140%	New turbine higher speed in accordance with possible runner setting level; capacity' level 165%	
Generator	100	New stator winding; capacity level 115%	New windings, iron core, poles and excitation; capacity level 135%	New generator same speed as existing unit; capacity level 160%	New generator of higher speed corresponding to turbine, capacity level 180%
Penstock	115	Sandblasting and repainting; capacity level 125%	New penstock for Turbine Discharge 1; capacity level 450%	New penstock for Turbine Discharge 2; capacity level 165%	
Source:					

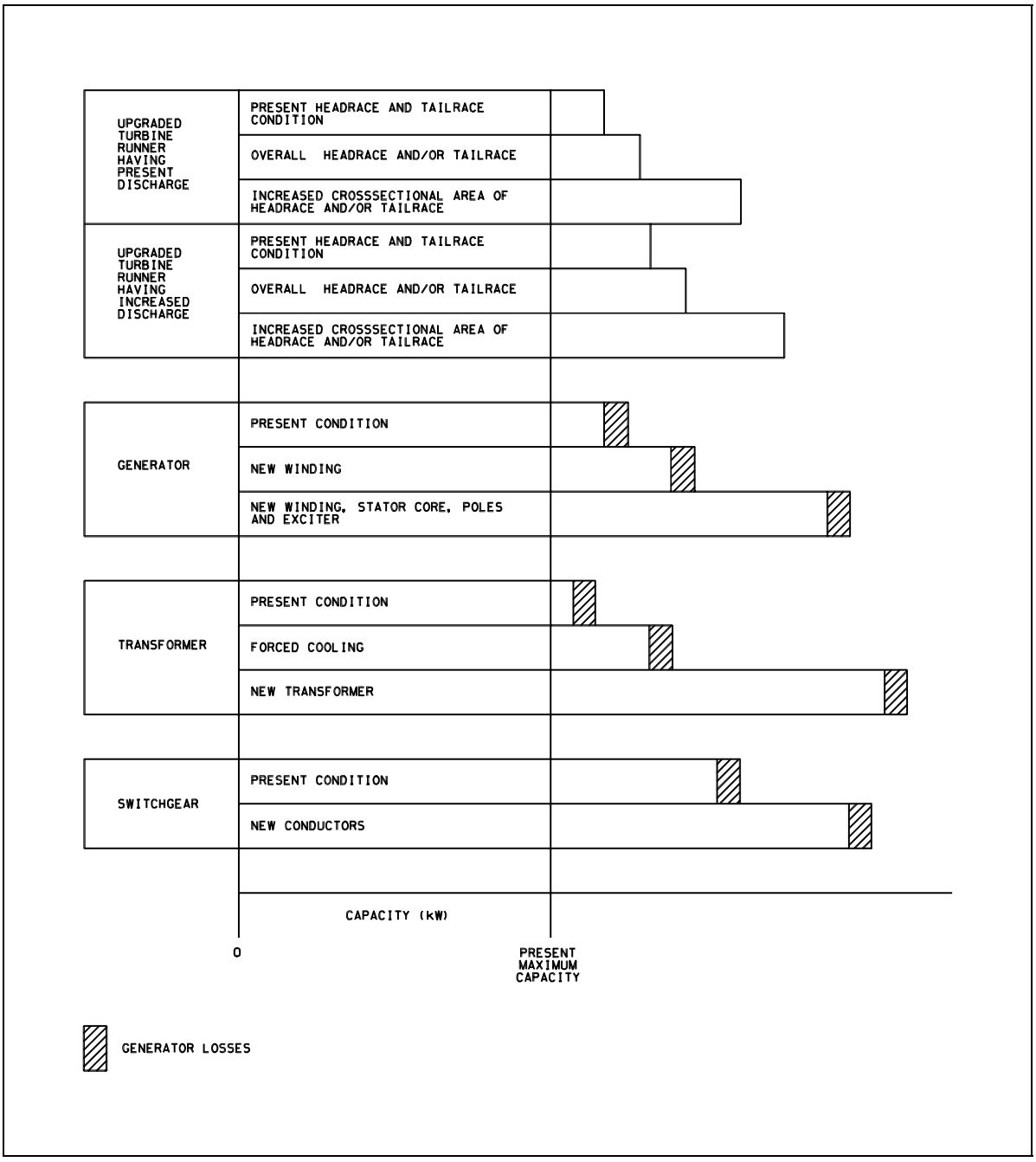

Figure 5-26
Alternatives to Increase Unit and Component Capacity

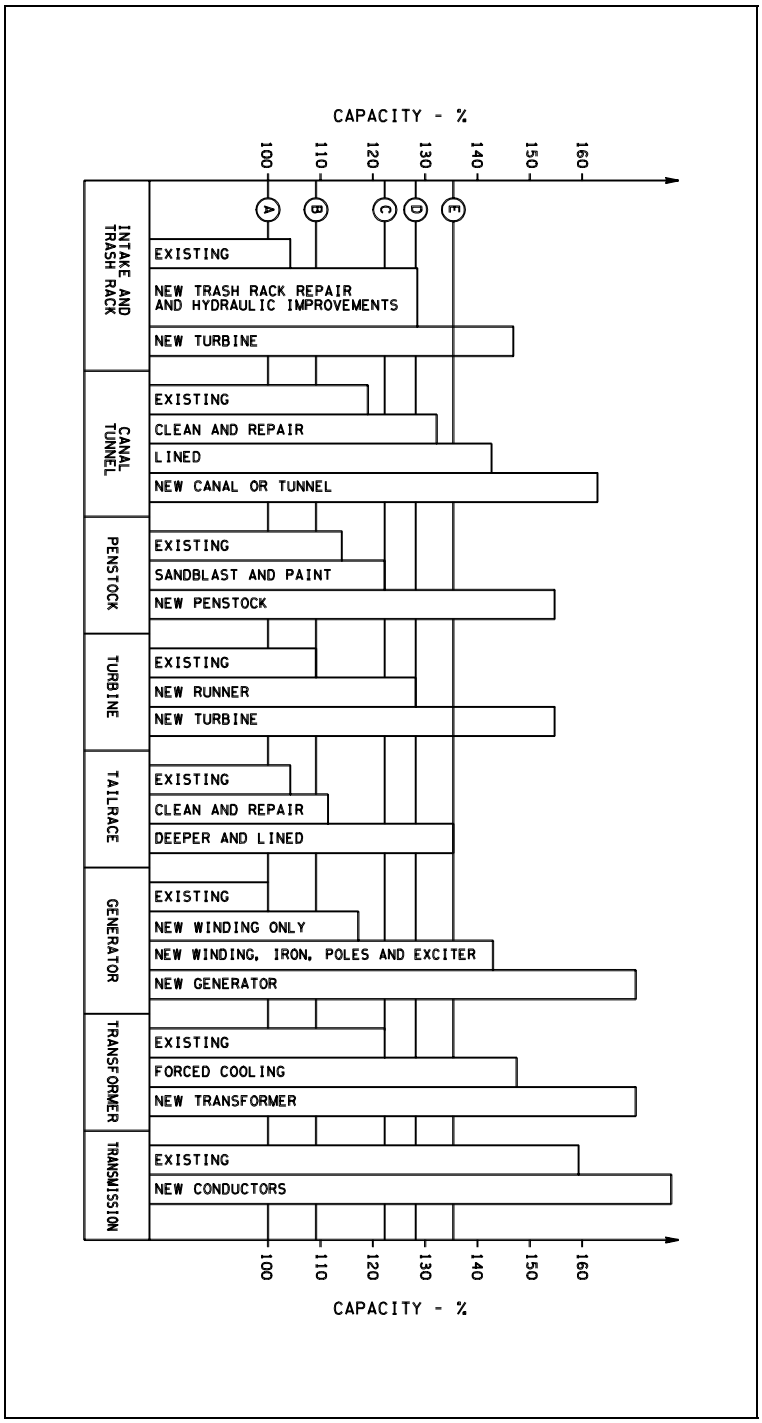

Figure 5-27
Developing Uprating Plans - Elimination of Bottlenecks
Source: Electric Light & Power, March 1987, pg. 25

5.9.4 Uprating by Identifying Deficient Components

A second approach to developing potential uprating plans is to identify deficient components. Although the bottleneck approach concentrates on components which limit plant capacity, this approach concentrates on unreliable components identified as being in critical condition during the screening process.

This more direct approach to identifying modernization plans can be used if the condition and reliability of the major components are in need of rehabilitation. In this method, a survey and checklist are prepared for each deficient piece of equipment. Included in the checklist are those components in poor condition, the potential capacity increase of rehabilitation alternatives, and those components affected by the various potential component replacements.

An example of this method is shown in Table 5-16 using the turbine as the deficient component. As shown in the table under Option Plan A, Refurbish Only, a capacity increase of 0 to 5% is possible by refurbishing the turbine and no other components are affected. Option Plan B includes runner replacement and a potential capacity increase of 5 to 30%, but also requires changes to the components indicated in the column. A checklist to assist in determining the interrelationships of components is provided in Figure 5-28. Once the components that limit power plant uprating are identified, several alternatives can be developed to achieve the desired over all plant improvements.

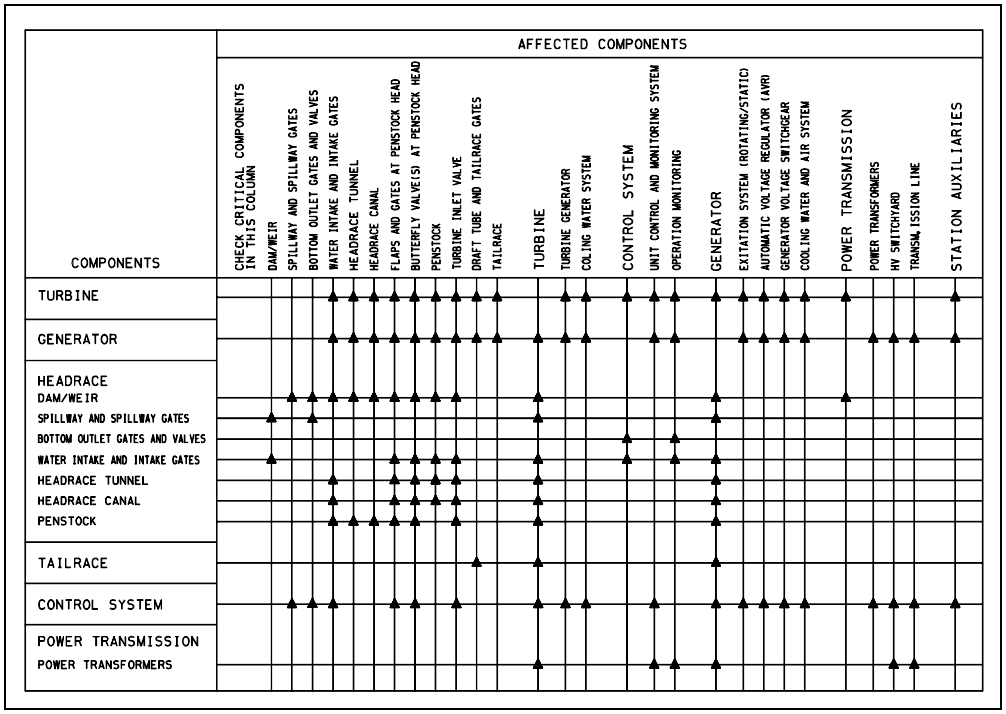

Figure 5-28
Checklist to Determine Affected Components

Table 5-16
Overall Modernization Plans Based on Turbine Upgrading Options

Component	Typical Capacity Increase (Uprating) Ranges and Typical Upgrade Requirements on "Affected Components"			
	Option Plan A	Option Plan B	Option Plan C	Option Plan D
Turbine	Refurbish only	Runner Replacement	New Turbine Internals	New Turbine in Existing Powerhouse
Typical Capacity Uprate	0 - 5%	5 - 30%	20 - 50%	30 - 100%
Intake Trashrack	Not Affected	Refurbish or Minor Improvement	Major Improvement or new	New
Canals	Not Affected	Refurbish or Minor Improvement	Major Improvement or new	Major Improvement or new
Penstock	Not Affected	Refurbish	Refurbish	New
Generator	Not Affected	Rewind	New	New
Transformer	Not Affected	Forced Cooling	New	New
Transmission Line	Not Affected	Not Affected	Larger Conductors	Larger Conductors

5.10 Consideration of Other Approaches to Improvement

To date this Section has explored the potential for improvements utilizing the existing turbine. There are other options beyond simply modernizing the existing machine which can be considered. Redevelopment refers to improvements that affect the powerplant, often including substantial modifications to the civil structures, and replacing the units of higher capacity or different design. These options will not be explored further in these Guidelines; however preliminary equipment cost data is provided in Section 6 to assist in such an evaluation and a general summary of redevelopment alternatives is provided in Table 5-17.

Table 5-17
Modernization Alternatives and Design Criteria

Modernization Alternative	Criteria
Replace the existing runner and turbine non-embedded parts with a new modern runner. Retain existing draft tube and distributor section.	The setting of the turbine runner remains unchanged. Uprating capability of the new unit may be limited by cavitation conditions. Changes to accommodate the new turbine are limited to modifications to the discharge ring and top of the draft tube. If the existing generator is used, the turbine speed remains unchanged. (Discussed in previous Sections.)
Replace the existing turbine with a new modern turbine. Retain the existing draft tube.	The setting of the turbine remains unchanged. Uprating capability of the new unit may be limited by cavitation conditions. Civil works to accommodate the new turbine are moderate. If the existing generator is used, the turbine speed remains unchanged.
Complete replacement of the turbine including draft tube by turbine of the same type.	A lower setting of the turbine runner allows a higher speed, higher capacity turbine within available space. Civil works are more extensive and may include foundations of the powerhouse. (Not considered in these Guidelines.)
Replace low head Pelton turbine with higher capacity Francis unit.	The setting elevation of the Francis turbine would be above tailwater unless powerhouse modifications are made. Capacity may be limited by cavitation conditions. (Not considered in these Guidelines.)
Replace low head Francis turbines with higher capacity propeller/Kaplan turbines or horizontal shaft propeller/Kaplan turbines - turbular or bulb units.	The extent of civil works modifications depends on the existing powerhouse arrangement which usually determines the feasibility. Capacity may be limited by cavitation conditions. (Not considered in these Guidelines.)

5.11 Input to Modernization Plan

The final task in the initial selection of modernization activities is to input them into the Life Extension and Modernization Plan (LEM Plan) in order to see their impact on plant economics. Volume 1, Section 4 details the methodology for incorporating identified opportunities into the LEM Plan. This is an important step in the iterative process of selecting life extension and modernization activities, as it will assist in determining whether the benefits of modernization justify the additional expenditure over the life extension alternative. The information on the pro forma "Equipment Modernization Opportunities" worksheet (Table 5-1), completed for each piece of mechanical equipment, should provide all of the necessary information for the LEM Plan at this pre-feasibility stage.

After initial financial and economic results are available for the preliminary LEM Plan, further studies are required to confirm that the selected modernization opportunities are feasible both technically and economically. Further inspection, testing and studies for the feasibility stage of analysis are described in Section 7 of this Volume entitled "Optimization of Alternatives".

6
ESTIMATES OF COSTS AND BENEFITS

6.1 Introduction

The costs and benefits of possible hydromechanical life extension and modernization activities for equipment are important factors in any decision regarding the future of a plant.

This section provides guidance for the following stages in identifying and defining life extension and modernization projects:

- screening level (Section 6.2)
- Life Extension and Modernization (LEM) Plan and the financial model/evaluation template (Section 6.3)
- feasibility level and project approval (Section 6.4)

In all considerations of costs and benefits, care must be taken in using the results from generic curves, tables and processes such as those given in these guidelines. The results are only approximations. Each plant and each individual unit studied by the user will have its own unique situation which will require consideration before using the information provided in this section. The Life Extension and Modernization Plan process is iterative and accordingly the accuracy of estimates will be required to improve with each iteration. Estimating considerations are discussed in Volume 1, Section 2.3.5.

All prices used in this section are in year 2000 dollars (US). Various indices are available to escalate dollar values for future years, including:

- Handy-Whitman Index of Public Utility Construction Costs.[1]
- Bureau of Reclamation Cost Index.[2]

[1] *Handy-Whitman Index of Public Utility Construction Costs*, published by Whitman, Requardt and Associates LLP, Baltimore, Maryland

[2] *Bureau of Reclamation Cost Index* published at the end of each quarter in Engineering News Record, published by the McGraw-Hill Companies, New York, New York

6.2 Cost Estimates at the Screening Level

6.2.1 Estimates for Life Extension and Modernization Activities

The cost estimates and delivery times presented in Section 6.2 are screening level estimates for complete turbine replacement and replacement of non-embedded parts only. The runner cost estimates provided in Section 6.3 can be used for screening level runner costs. Many factors affect the costs of turbine components and screening level estimates are only order of magnitude cost estimates.

6.2.2 Complete Turbine Replacement Cost and Delivery Time

The removal of a complete turbine and installation of a replacement turbine, with associated civil works, is considered beyond the scope of these Guidelines. It is helpful, however, to compare the costs of some life extension and modernization activities discussed in this Volume to those of installing a new turbine.

The cost of turbine replacement depends on the turbine type, physical size and design head. The factory cost (supply only) for replacement turbines can be estimated from Figures 6-1 through 6-6. The cost for propeller turbines can be estimated to be 80% of the cost of Kaplan turbines in Figure 6-3. The costs for Kaplan turbines in Figure 6-3, are for an installation with a concrete semi-spiral case. If a steel spiral case is required with the turbine, the costs should be increased by 10 %. The costs do not include the governor hydraulic pressure units and associated controls (Section 6.3.4).

If only the turbine non-embedded parts (for example, the runner, headcover, wicket gates, bearing, etc.) are purchased and installed within the existing embedded parts (stay ring, discharge ring, draft tube liner, pit liner, spiral case), the following costs will apply:

- Francis turbine and pump turbines — 60% of cost in Figures 6-1
- Pump turbine — 60% of cost in Figure 6-2
- Kaplan turbine — 70% of cost in Figure 6-3
- Vertical Pelton turbine — 60% of cost in Figure 6-4
- Horizontal Pelton turbine — 85% of cost in Figure 6-4

The cost of installation can be estimated as 15 to 20% of turbine cost. The delivery times for the first shipment of components, new runner, and complete turbine and installation time can be estimated from Figure 6-7.

For runner replacement costs specifically, Tables 6-8 to 6-12 in Section 6.3 can be used.

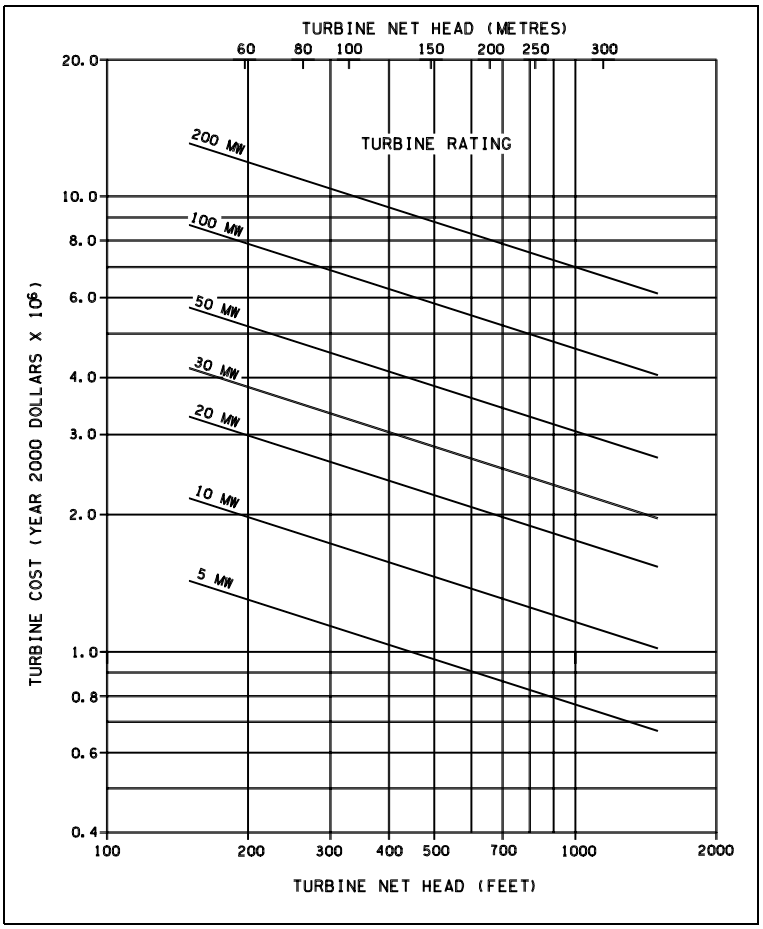

Figure 6-1
Francis Turbine Costs
Non-embedded parts costs are approximately 60% of the above.

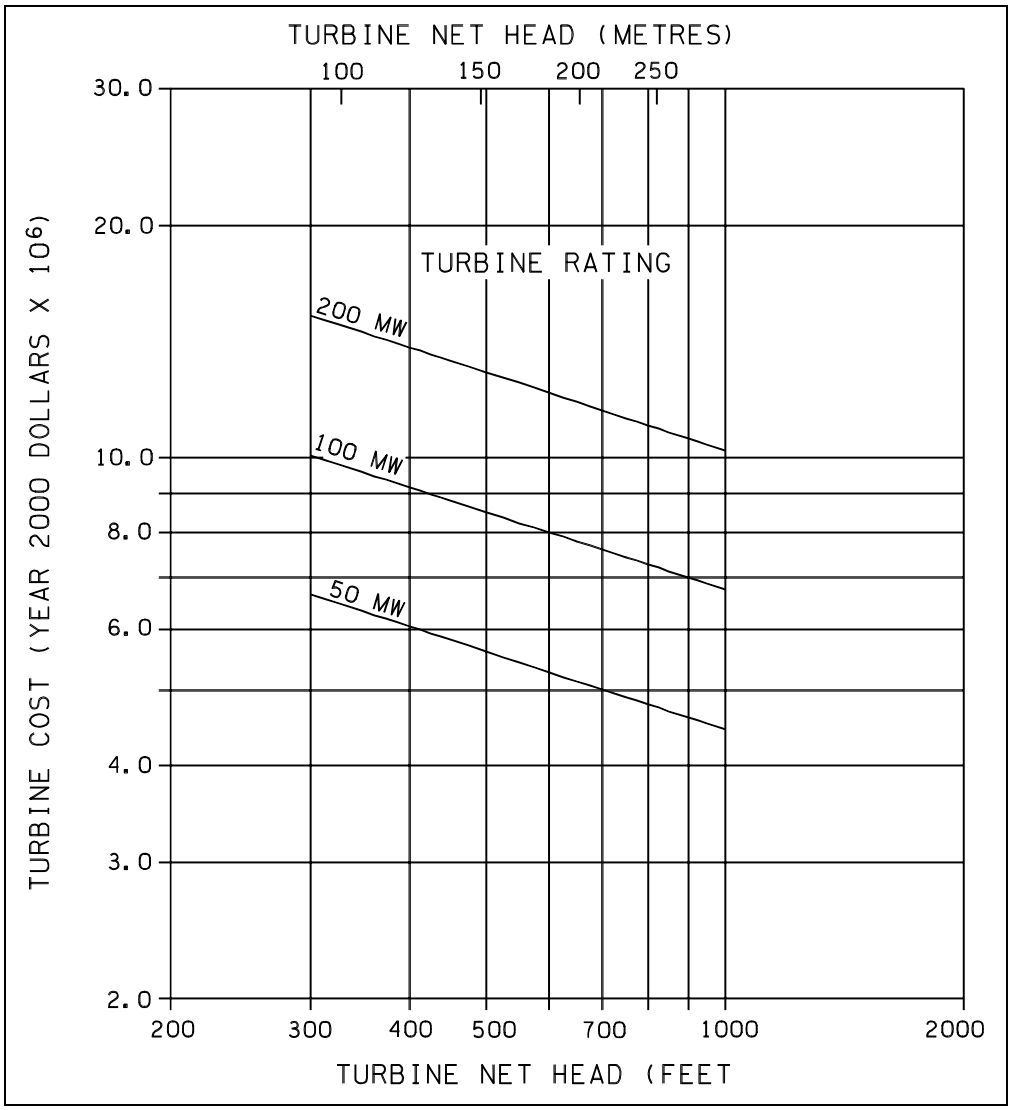

Figure 6-2
Pump-Turbine Costs
Non-embedded parts costs are approximately 60% of the above.

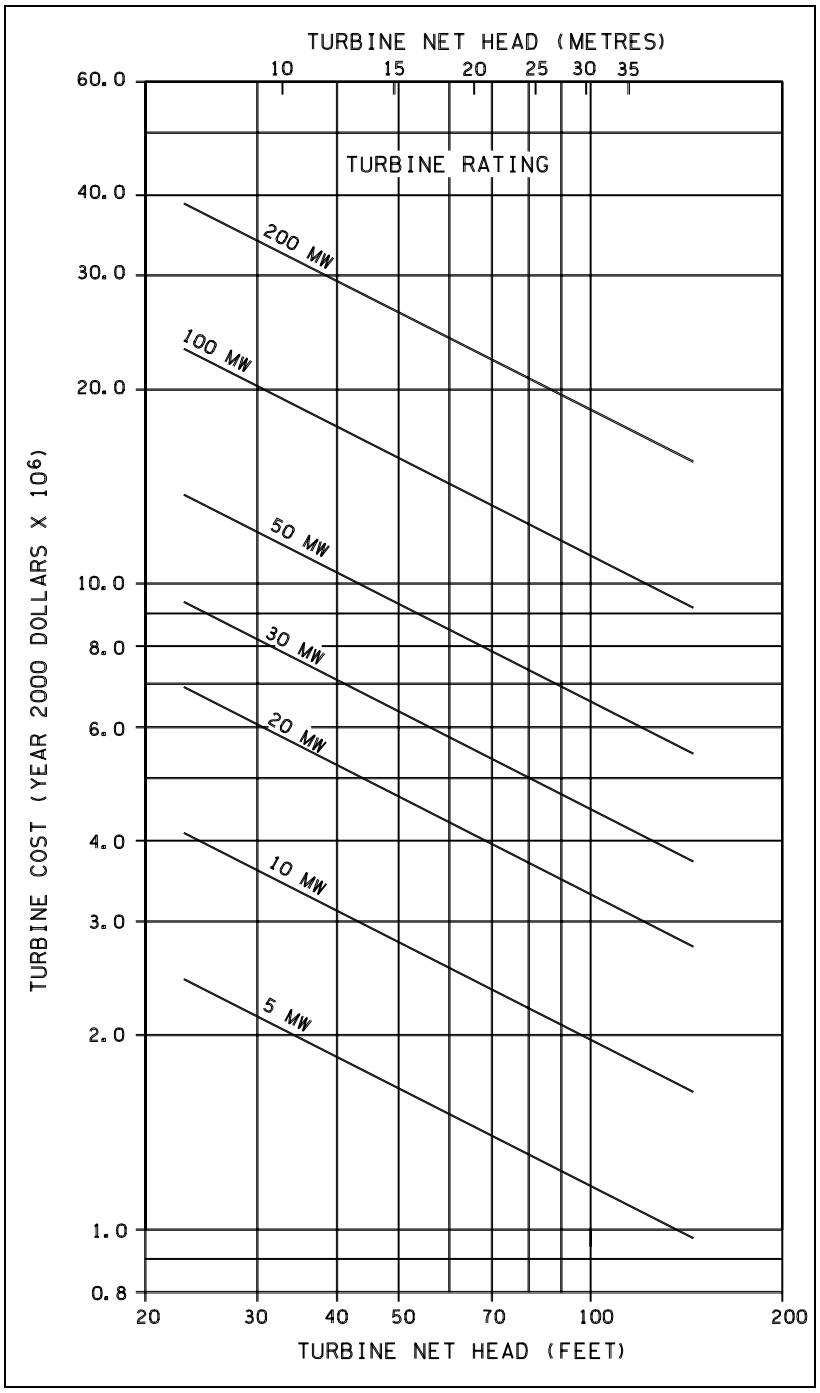

Figure 6-3
Kaplan Turbine Cost
Non-embedded parts costs are approximately 70% of the above.

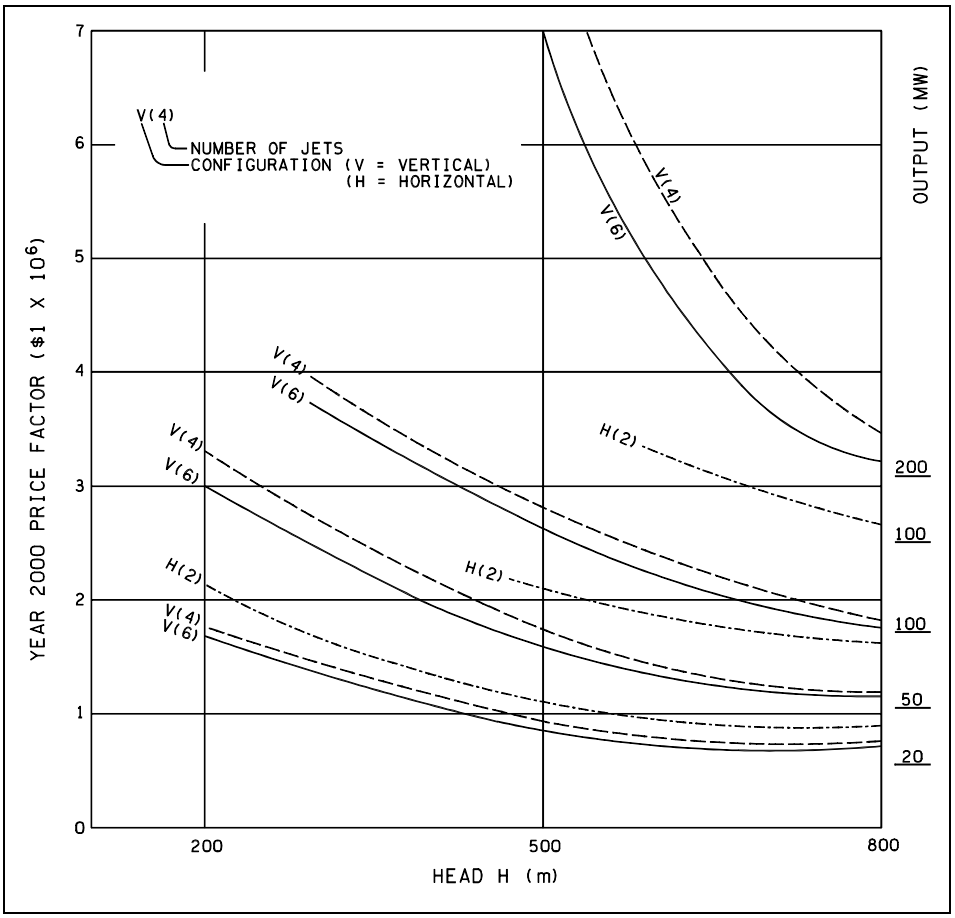

Figure 6-4
Price Factors for the Supply of Pelton Turbines with Different Arrangements and Outputs as a Function of Net Heads

For vertical Pelton units, non-embedded parts costs are approximately 60% of the above.
For horizontal Pelton units, non-embedded parts costs are approximately 85% of the above.

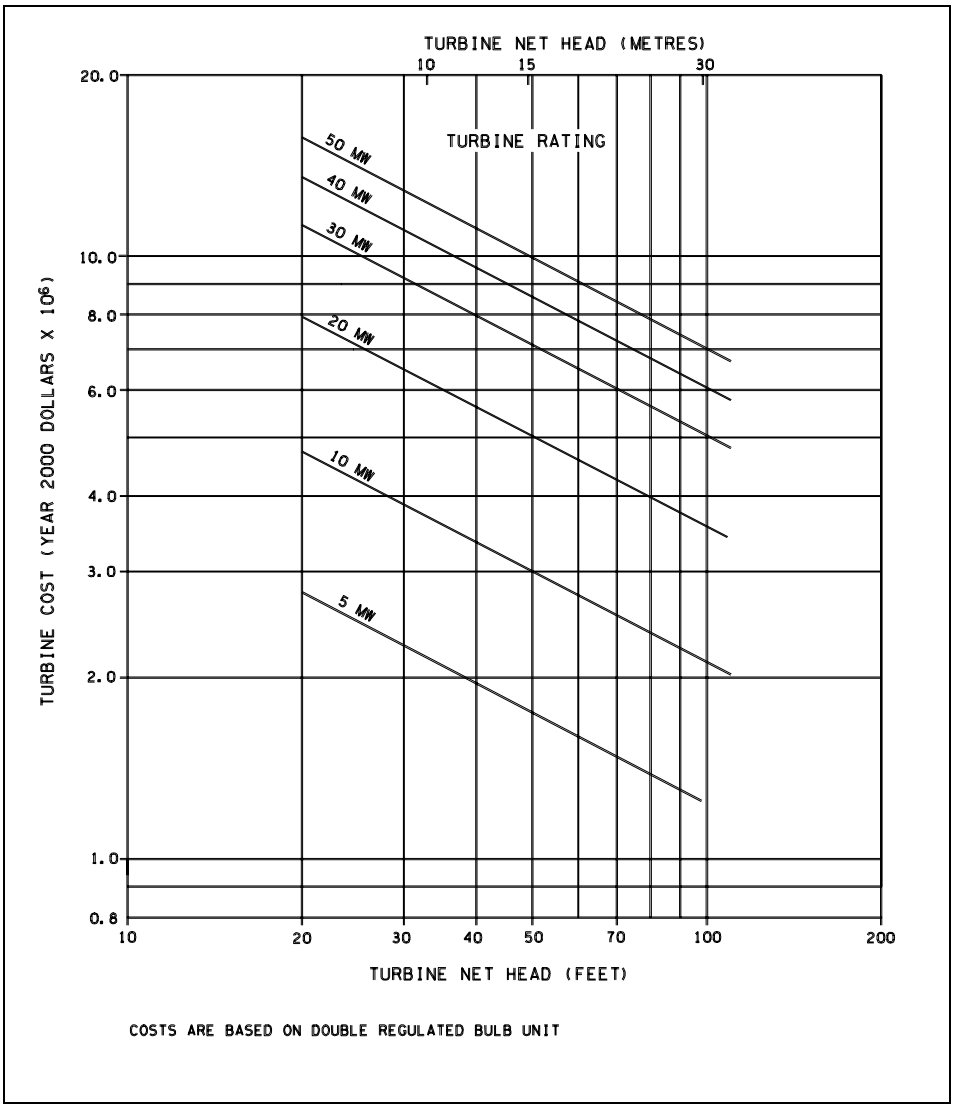

Figure 6-5
Bulb Turbine Cost

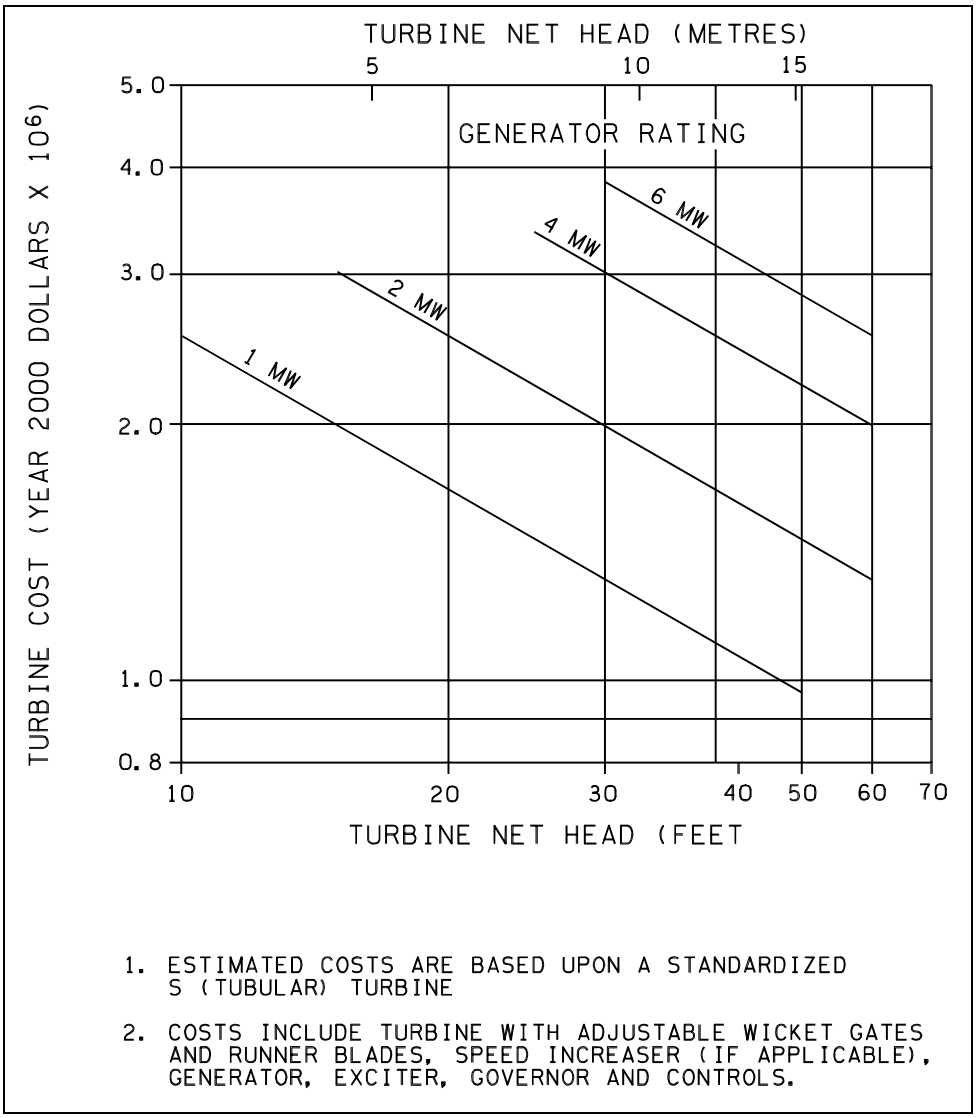

Figure 6-6
S (Tubular) Turbine Cost

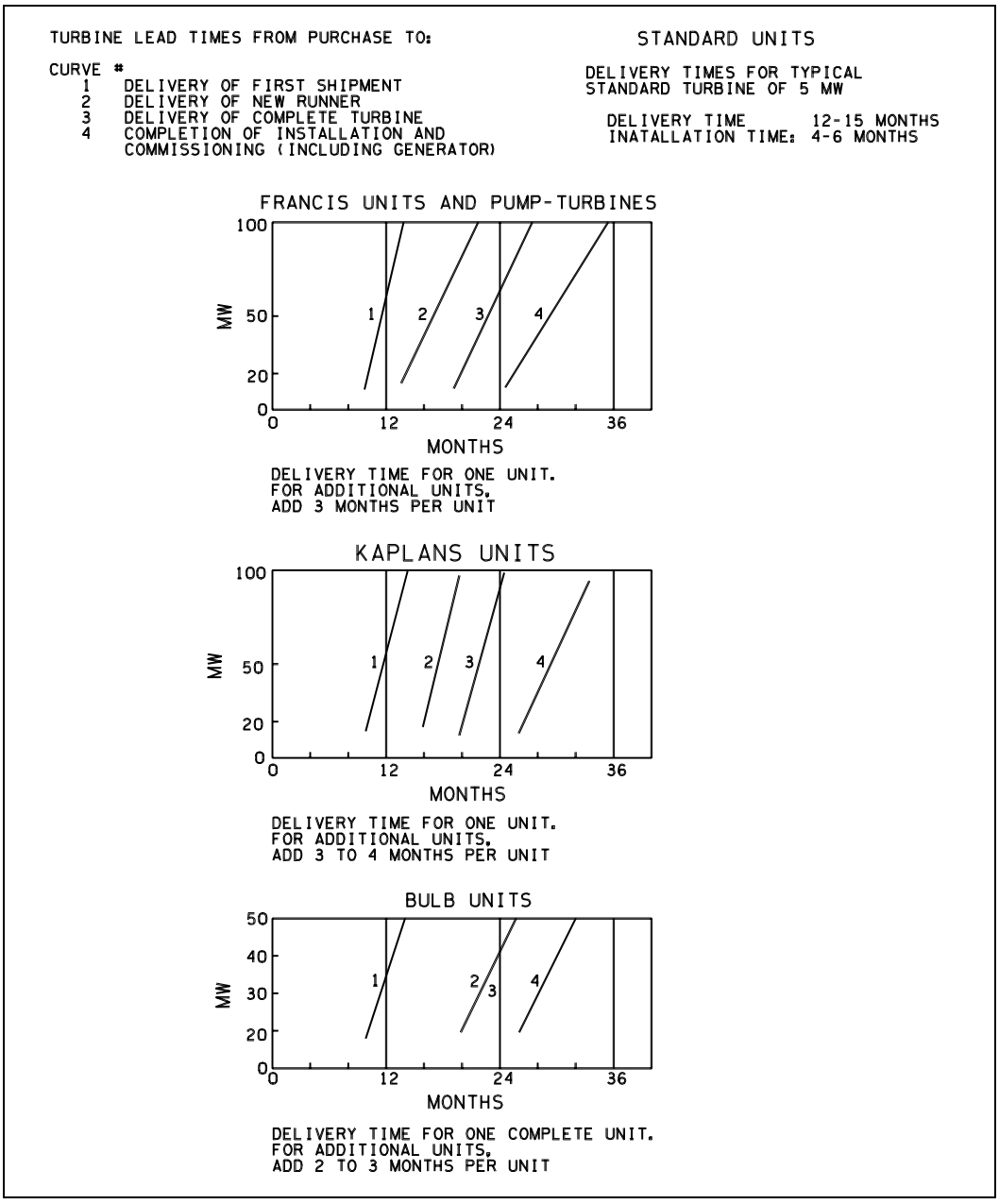

Figure 6-7
Turbine Lead Times from Purchase to Unit Commissioning

6.3 Cost Estimates for Life Extension and Modernization Plans

Cost estimates are usually not as accurate as the technical estimates of capacity and efficiency. Bids for new turbines and replacement runners may vary by as much as 100%. A major uncontrollable factor which influences cost and delivery time is the backlog of work in the manufacturer's plant. Therefore, the costs and delivery times presented should only be used as general guidelines.

The estimates derived from this section can be used in conjunction with work associated with Volume 1, Section 4 and Sections 4 and 5 of this Volume. More detailed cost estimates which are required for feasibility level studies and the project approval stage should involve input from manufacturers (Section 6.4).

6.3.1 Turbine Life Extension Cost and Delivery Time

Turbine life extension costs (refer to Table 6-1) will range from the cost of the minimum turbine life extension to a complete turbine replacement (Section 6.2.2). The cost for turbine rehabilitation, delivery, and installation can be broadly estimated from the following:

Table 6-1
Turbine Life Extension Costs and Estimated Delivery and Installation Times

Cost for Turbine Life Extension as a Percentage of New Turbine Replacement Costs			
	Minimum Life Extension (%) (% of new turbine replacement cost)	Major Life Extension (%) (% of new turbine replacement cost)	Complete Replacement (%) (% of new turbine replacement cost)
Turbine Rehabilitation Cost	10	20	100
Disassembly and Reassembly Cost	10 - 15	10 - 15	15
Delivery Time	6 months	6 to 12 months	12 to 30 months
Installation	1.5 to 4 months	1.5 to 4 months	2 to 6 months

6.3.2 Runner Modernization Costs and Delivery Time

General

Costs for runner modernization can involve for the following activities:

- Model development tests
- Design of the upgraded runner
- Patterns for casting, or die for plate forming

- Material costs
- Welding of runner components
- Machining and finishing
- Quality control
- Transportation and other duties
- Installation
- Commissioning and final testing

In this section, runner modernization costs are subdivided into the following four items:

A. Model development tests

B. Runner supply (design, manufacture and delivery)

C. Installation

D. Commissioning and Final testing

In addition, the installation of a new runner may be combined with the following other modifications to improve turbine performance:

- Stay vane modifications so that inlet angle better matches the approach flow
- Wicket gate modifications or replacement to improve the hydraulic design
- Discharge ring modifications on a Francis turbine to allow a longer runner band which improves the cavitation characteristics
- Draft tube modifications to improve energy recovery in the draft tube

In addition, installation of a new runner may require modifications and improvements to turbine parts such as stationary wearing rings on Francis turbines and the discharge ring on Kaplan turbines. Machining may also be required for turbine components to correct wear, out-of-roundness, misalignment, concrete movement, or other causes. Those improvements are site and case dependent and require expert assessment by inspection and measurements of the dismantled machine and are not covered in detail in these guidelines.

Runner Modernization Costs

Item A - Model Development and Test Costs

The cost to design, construct and test a homologous turbine model is approximately $500,000 to $700,000 depending on the specific tests performed. These costs pertain to Francis, propeller or Pelton turbine models. The cost for a Kaplan or pump/turbine model will be approximately 10% higher. These costs include fabrication of the complete model turbine.

If fabrication of only a part of the model turbine is required, the development costs will be lower and can be one half of the costs indicated above.

For runner upgrades, some owners prefer to conduct a model test on the existing runner as well as the new runner. This allows the incremental efficiency improvement of the runner upgrade to be determined with considerable accuracy. The added cost to perform a model test on the existing runner is between $100,000 and $150,000.

Because the costs for model test are relatively high, and less expensive analytical methods are available to accurately design replacement runners, model tests are not usually performed for small capacity turbines. Users should consider the costs and benefits of model development tests to determine whether they should be performed. Computational Fluid Dynamics (CFD) has facilitated detailed examination of the characteristics of fluid flow and optimization of runner design. CFD has improved dramatically over the last few years and, in many cases, can be relied upon in place of physical hydraulic model testing. The investment required for physical testing is often not justified for units of less than 50 MW capacity (unless upgrade of several identical units is contemplated), and CFD is often being used in place of model testing for this category of turbine.

For a plant with multiple units of relatively high capacity (>100 MW) a competitive model test program is sometimes implemented. With this approach, two or more manufacturers design and test model turbines, with a final test of all designs conducted at an independent laboratory. The selection of the preferred manufacturer is made after the final model test. The owner typically covers the costs of all participating manufacturers and the overall model test program which can cost from $1,300,000 to $1,800,000. (Refer to Section 8.2.1).

Item B - Design and Manufacture of a New Runner Costs

Turbine manufacturers have extensive experience, technical capacity, and modern analytical methods to design upgraded runners which are compatible with the old turbine without the aid of model tests. Foundries, or fabrication/machining plants on the other hand, may be capable of providing a new runner based on the old runner dimensions. Therefore, while bids from foundries or fabrication/machining companies are often lower than those from turbine manufactures, the runner provided by these companies, will likely not have improved performance.

The cost of a new turbine runner, as a function of diameter, is shown on Figure 6-8. These costs are for a new runner, designed specifically for the project. If the runner is a duplicate of the existing runner, the costs may be about 30% lower.

The Kaplan runner cost includes new runner blades in addition to a new hub with blade operating mechanism.

In some cases, the runner hub can be retained. Minor mechanical problems, such as oil leakage, can usually be corrected by modifying the seal design, which does not normally require hub replacement. Hub replacement will be required:

- If there is physical damage to the hub and blade trunnion bearing supports;
- Because of major operating problems with the blade adjusting mechanism which may have required welding the blades to the hub;
- If the manufacturer's design has a smaller diameter hub which allows increased flow/output;
- If the number of blades is reduced (such as from six to five blades or five to four); or
- If there are changes to the blade servo operating system.

Changing the number of runner blades requires detailed investigation and model testing and is beyond the scope of these guidelines.

The cost data in Figure 6-8 is for one runner and is in year 2000 US dollars. The costs for subsequent units will be lower because design costs are independent of quantity and turbine size, and can be distributed over subsequent units. The patterns for the runner casting, or the steel former for pressing blades, could also be used for several units. Therefore, when 4 to 8 runners are purchased which have the same design, the cost per runner can be reduced 10 to 20%.

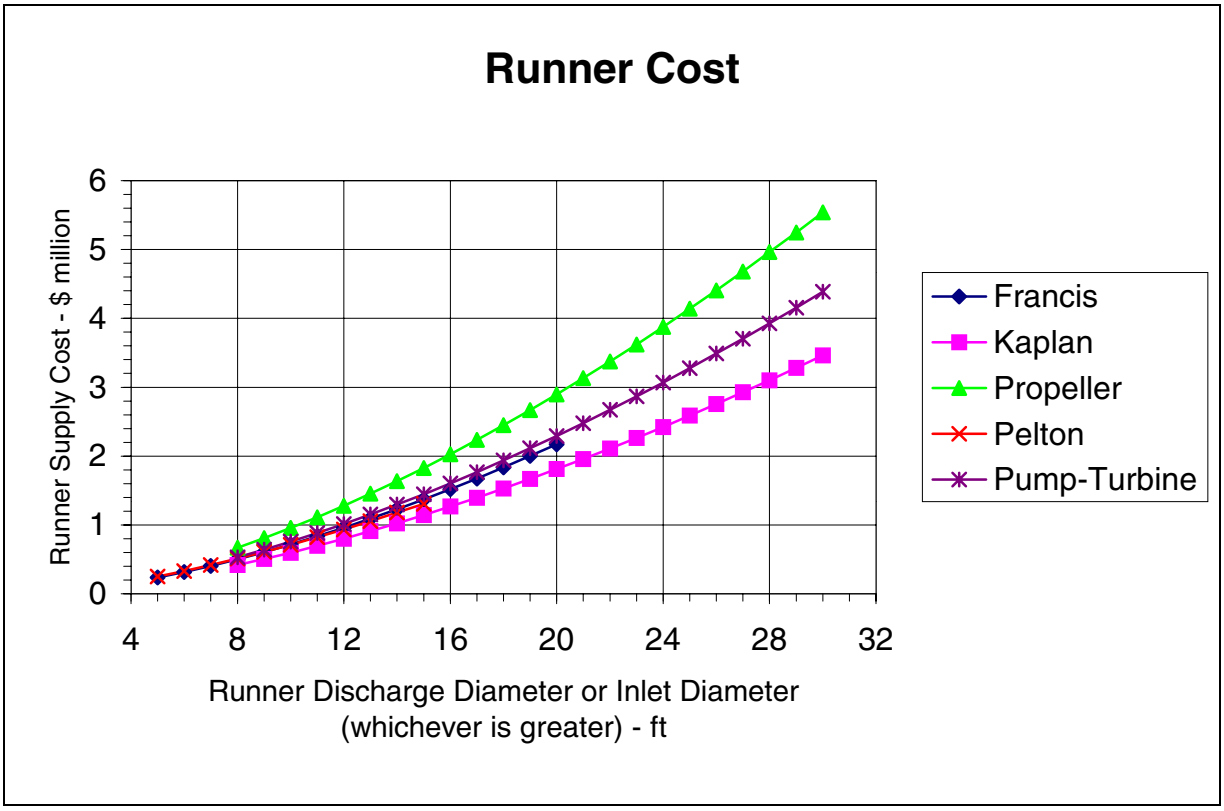

Figure 6-8
Runner Costs

Item C - Installation Cost

If the old runner is the only component that must be replaced, down time can be reduced to a minimum of 6 to 12 weeks. However, when Kaplan runner blades are replaced, the old runner may require shipping to the manufacturer's shop to properly balance the runner and overhaul the hub which could add up to an additional 2 months downtime. A new hub should be considered if the savings in unit downtime and shipping costs exceed the cost of a new hub.

The cost of installation depends on an owner's ability to support the work. For example, installation supervision provided by a runner manufacturer may cost approximately $1,000 per day. Generally runner upgrading is combined with a general overhaul of the turbine, and therefore, the installation cost is often incorporated with the overhaul costs. However, sometimes the total unit dismantling and reinstallation costs must be included as part of the runner upgrade. If this is the case, the cost for dismantling and reinstallation including runner installation can be estimated from Figure 6-9. These costs apply to a vertical unit where the generator and turbine must be dismantled for runner installation. For a unit where the runner can be removed from below the turbine distributor or from between the turbine and the generator, or for horizontal units where the runner can be removed without dismantling any of the generator, the runner installation costs can be assumed as 10 to 25% of the runner supply cost, depending on the complexity for installation.

Item D - Commissioning and Final Testing Costs

The cost of commissioning includes placing the upgraded turbine into operating and verifying the performance guarantees by field tests. Commissioning tests usually require a supervisor from the manufacturer, two engineers, and necessary test instrumentation. The tests are conducted over a two-week period and require the following costs.

Table 6-2
Commissioning Costs

Description	Cost Per Unit
Verify Output Guarantee	$10,000
Index Test	$10,000 to $20,000
Efficiency Test on High Head Turbines	$30,000 to $60,000/test
Efficiency Tests on Low Head Turbines	$40,000 to $100,000/test

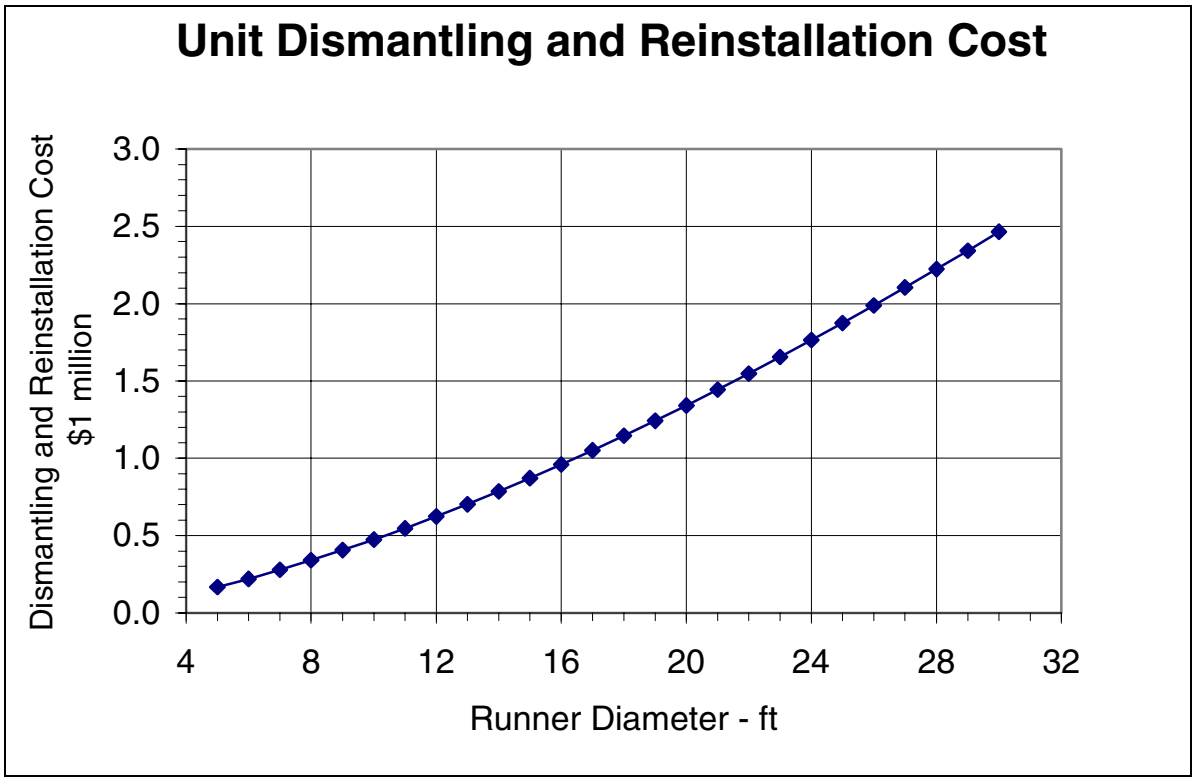

Figure 6-9
Unit Dismantling and Reinstallation Cost

Costs of Other Modifications in Association with Runner Modernization

For a runner upgrade which results in an increase in unit capacity it is important that other components also be assessed. This includes the generator, main power conductors, current breakers and transformers. Equipment to consider is described in Volumes 3 (Electromechanical), 4 (Mechanical Auxiliaries) and 5 (Electrical Auxiliaries) of these guidelines. If upgrade or replacement of this equipment is necessary solely because of increased turbine output, the cost of upgrade/replacement should be included in the cost of runner upgrade.

As mentioned in Section 6.2.1, runner upgrade is sometimes accompanied by stay vane modifications, so that the stay vane angle better matches the angle of approach flow. The cost for the modifications are highly dependent on the extent of the changes to the stay vane profile. However, as a rough guide, stay vane modifications could be estimated as 20% of the runner supply cost.

Runner Modernization Delivery Time

The preparation of bidding documents and the expected bidding and evaluation period are as follows:

- Preparation of Bid Documents:

  Standard Unit - 1 month

  Custom Unit - 1 to 3 months

- Bidding and Evaluation period: 2 to 4 months

The delivery time required for runner design and delivery depends on the runner diameter and can be estimated as follows:

Table 6-3
Runner

Item	Runner Diameter	
	3 to 10 ft (1 to 3 m)	10 to 25 ft (3 to 8 m)
Model Testing	3 to 6 months	6 to 12 months
Design and Fabrication	6 to 12 months	9 to 15 months
Installation	1.5 to 3 months	2 to 4 months

6.3.3 Turbine Inlet Valve Cost and Delivery Time

Dimensions

The major overall dimensions for spherical and butterfly valves can be determined from Figures 5-16 and 5-17 respectively in Section 5 of this Volume. The valve dimensions are provided as a function of the valve diameter, D.

Cost and Lead Time

The supply cost of spherical and butterfly valves can be determined from Figures 6-4 and 6-5. The figures indicate the valve cost as a function of valve diameter and head. The cost of valves between the head ranges indicated may be obtained by interpolation.

Figure 4-21 in Section 4 shows the delivery time required from the purchase order to delivery, installation, and commissioning of new nonstandard butterfly and spherical valves. The delivery

schedules shown include a completely redesigned valve, plus any additional corrosion protection, and is indicated as a function of valve diameter.

The valve costs in Figures 6-10 and 6-11 include delivery, but exclude the cost of the control system and valve installation costs. The cost of a control system for an inlet valve can be estimated to be 15% of the new spherical or butterfly valve. Installation costs for the valves can be estimated as 15% of the valve.

6.3.4 Governor System Cost and Delivery Time

Because of the very wide range in governor types and sophistication, only rough guidelines can be provided for estimating purposes. The cost for supply and delivery a new turbine governor system including a hydraulic pressure unit and digital governor controls ranges from $180,000 for a 40 MW unit to $1,000,000 for a 300 MW unit. Straight line interpolation can be used to determine a "ball-park" governor cost for other unit sizes. Installation will be approximately 25% of the supply cost.

The lead time for delivery from the time the governor is ordered is approximately 12 months.

The costs to retrofit an existing mechanical governor with new control valves and modern digital controls can be estimated as 50% of the cost of a new governor system.

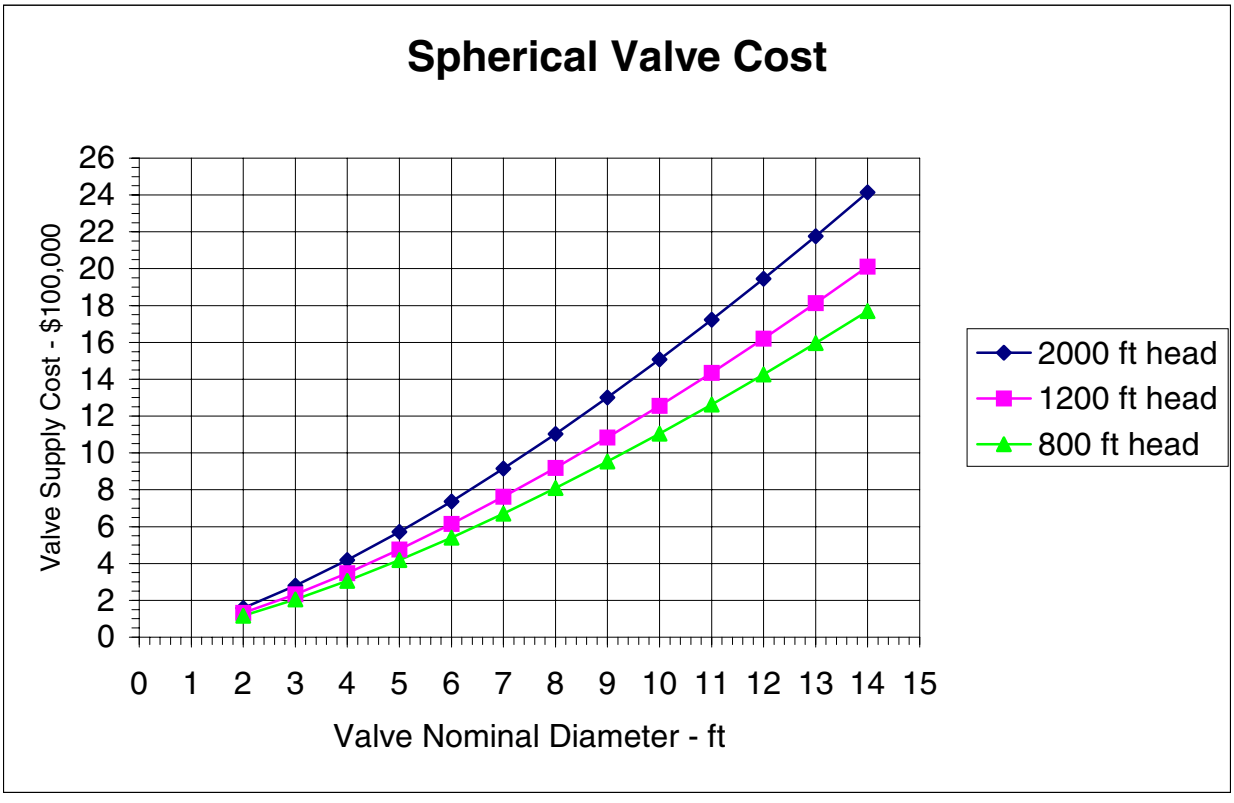

Figure 6-10
Spherical Valve Cost

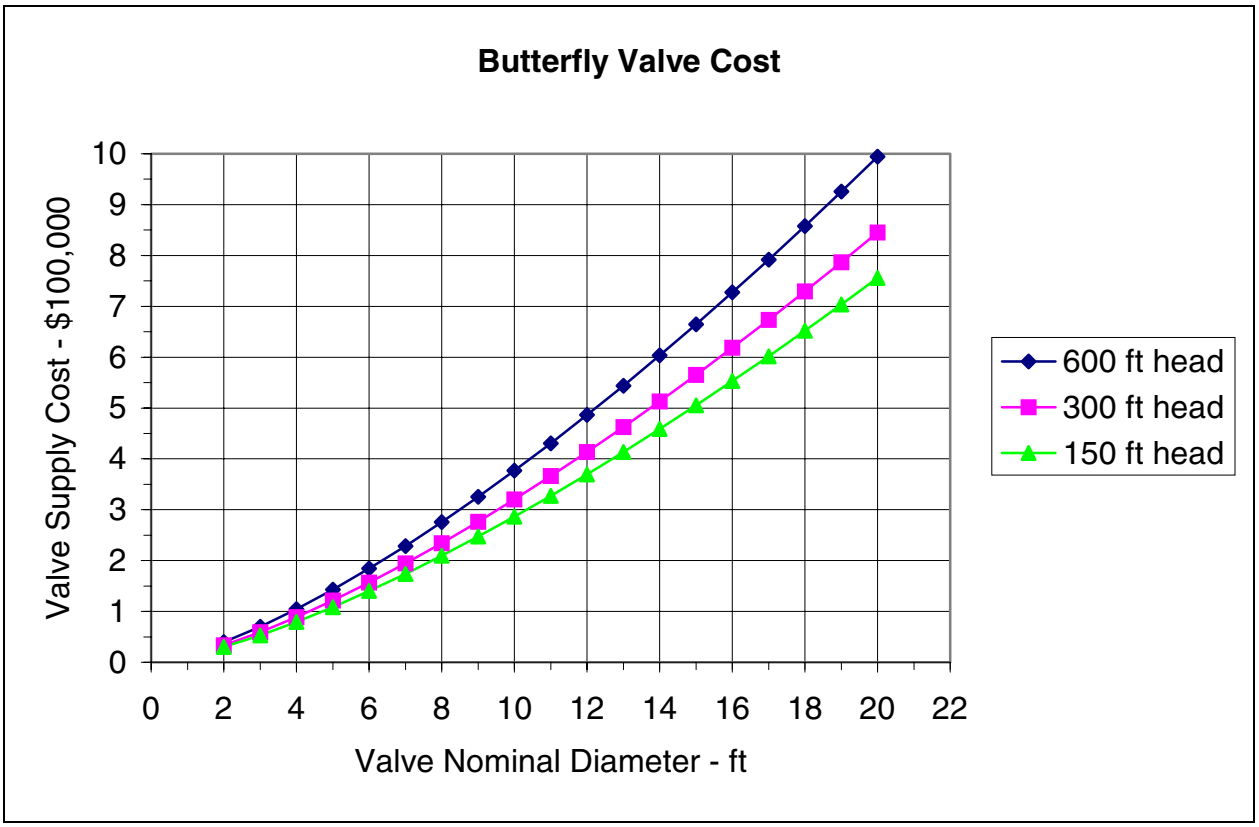

Figure 6-11
Butterfly Valve Cost

6.3.5 Project Costs

The estimated costs of a project usually include:

- Direct costs
- Contingency
- Escalation
- Indirect costs
- Interest during construction (IDC)
- Other costs

Capital costs are those that result in an asset improvement and include all the costs above except for "other costs" which are generally under the heading of Operations and Maintenance.

Each of the areas above will be discussed briefly below for completeness. The use of the example electronic economic/financial evaluation template provided with Volume 1, Section 4.9 will simplify the process for evaluating the impact of the hydromechanical activities on the plant or facility. The template eliminates the need to calculate individual contingencies, escalation and

IDC for each identified project, as these are set for all projects entered into the template in the "Assumptions" area of the template. Costs are also used as input in the optimization of hydromechanical improvements.

Capital Costs

Capital costs for a project consist of the direct costs, contingency, escalation, indirect costs, and interest during construction.

- Direct Costs - Direct costs include the costs of all direct equipment, material, and construction costs associated with disassembly, assembly and testing and are discussed in Sections 6.2 and 6.3.
- Contingency - The contingency to provide for inaccuracies in the direct costs estimates depends on the confidence level of the direct costs. For the estimates for LEM Plans, a contingency factor of 20 percent (CF = 0.20) is suggested.
- Escalation - Escalation is the annual increase in costs due to inflation and other factors, such as material and labor costs. The direct costs determined from these guidelines are in 2000 dollars (US) and should be escalated to the midpoint of the construction period, as determined from the Milestone Schedule. The escalation factor can be determined from the following equation:

  $$\text{Escalation Factor (EF)} = (1 + e)^n - 1, \qquad [6\text{-}1]$$

  Where

  e = annual escalation rate in decimal value, and

  n = number of years between the date of direct cost dollar values and the date of midpoint of construction.

The value to be used for escalation can be determined from either the Handy-Whitman or USBR indices as described in Section 6.1. A suggested value is 3.0 percent per year (e = 0.03).

- Indirect Costs - Indirect costs consist of the costs for administration permits, licensing, engineering, construction management, training, and startup. For the runner modernization considered in these guidelines, an indirect cost factor (ICF) of 20 percent (ICF = 0.20) is suggested.
- Interest During Construction (IDC) - IDC is the interest paid on the money borrowed to finance the implementation of the plan. IDC is calculated from the midpoint of the Milestone Construction Schedule to the date of commercial operation. IDC is only applicable to plan costs treated as capital improvements where the costs are to be included in a rate base. For plans in which costs are treated as maintenance costs, IDC should not be applied. Similarly, for upgrade projects completed in less than a year, interest during construction is insignificant and may be excluded. The rates to be used can be determined from one of the following equations:

$$\text{IDC Factor (IDCF)} = (1 + r)^n - 1 \text{ (compounded)} \quad [6\text{-}2]$$

$$\text{IDC Factor (IDCF)} = r \times n \quad \text{(simple)} \quad [6\text{-}3]$$

where

r = interest rate in decimal value, and

n = number of years from the midpoint of construction to the date of operation.

Interest rates are typically 3 to 5 percent above the escalation rate. A suggested value is 9 percent (r = 0.09).

Present Value of Total Capital Cost

In present value evaluations, the total capital costs of a plan are not the dollar value used for the evaluation. The value required is the present value of costs incurred due to the commitment of the total capital costs. These costs include taxes, insurance, depreciation, return on investment, finance charges, and other administrative costs. These costs are called "fixed charges" and are typically assessed as a percentage of the total capital costs each year. Therefore, the fixed charges vary each year as the total capital costs vary. To simplify economic evaluations, the fixed charges can be converted to uniform annual payments called levelized annual fixed charges. This uniform annual payment is computed by dividing the sum of the present valued annual fixed charges over the economic life of the project by the sum of the present value factors. The uniform annual payment divided by the total capital cost is the levelized annual fixed charge rate.

The present value of these fixed charges corresponds to the date of commercial operation. This value needs to be present worthed to the date of the study and is the dollar value required for total present value evaluations in these guidelines. The present value of the total capital costs is the fixed charge factor times the total capital costs. The fixed charge factor is calculated as follows:

$$\text{Fixed Charge Factor (FCF)} = \text{LAFCR} \times \text{SPWF}, \quad [6\text{-}4]$$

where

LAFCR = the levelized annual fixed charge rate in decimal value, and

SPVF = the sum of the present value factors for the economic life of the modernization.

SPVF is calculated as follows:

$$SPVF = \frac{(1+i)^n - 1}{i(1+i)^n} \qquad [6\text{-}5]$$

where

i = the present worth discount rate in decimal value, and

n = the number of years in the economic life.

For organizations with ongoing improvements, these values may be readily available. However, when the values cannot be easily calculated, suggested values for FCF are 1.10 for public agencies and 1.30 for investor-owned utilities. The fixed charge factor is a number developed to quickly calculate the present value of the total capital cost in lieu of calculating the annual present value of the fixed charges and summing.

The present value fixed charges presented previously are based on the date the upgrade plan is put into commercial operation. These costs must be adjusted to the date of the study by multiplying by the present value adjustment factor. The present value adjustment factor (PVAF) is calculated as follows:

$$PVAF = 1/(1+i)^t \ , \qquad [6\text{-}6]$$

where

i = discount rate (0.09), and

t = number of years between the study and commercial operating date of plan.

Other Costs

Any other costs should be estimated and added to the total cost. For example, such costs might include the increased operation and maintenance (O&M) costs incurred while a unit is modernized.

The sum of the present value of the following costs - total capital and other costs - gives the total present value of upgrading, which is then compared to the operating benefits of the modernization plan. The present value of these costs should be at the date of the study.

6.4 Cost Estimates at the Feasibility and Project Approval Stage

While the cost estimates presented in the preceding subsections are suitable for screening and planning studies, estimates with reduced uncertainty will usually be necessary for project

approval, prior to implementation. Volume 1, Section 2.3.5 discusses various estimating considerations.

Indirect cost and interest during construction may require review to check any revision to the owner's specific financial/economic parameters. The use of the Model will reduce or negate this requirement if the appropriate parameters are initially entered into the Supporting Tables portion of the Model.

Cost estimates for supply of hydro mechanical equipment should be obtained from turbine manufacturers, or else developed from actual prices for previous projects of similar type capacity and physical size.

Life extension costs should be based on costs for previous projects of similar scope. In absence of any cost data the information from Section 6.3.1 can be used. Similarly, if possible, costs from previous projects should be used for dismantling and re-installation if available. If not, the information from Section 6.3.1 can be used.

In addition, cost information is also used as input for any optimization studies for hydromechanical equipment.

Depending on the confidence in the cost estimate, it may be possible to reduce the contingency to as low as 10 percent of direct cost. The owner's policy on contingencies however, will determine the contingency percentage to be included.

6.5 Energy and Capacity Benefits from Modernization

6.5.1 Energy

The expected energy benefit of a hydromechanical modernization activity will be refined as the planning process moves from the formulation of a LEM Plan through to the feasibility process. An initial estimation of energy benefits from a particular activity can be gained from the methods described in Section 5. During the feasibility process in Section 7 of both Volumes 1 and 2 the initial estimates of energy benefits will be refined through more detailed analysis and discussion with manufacturers.

The benefits of a modernization activity can be compared against the 'Base Case' for the plant. Usually the Base Case will include all activities necessary to maintain the plant at its present output.

For the existing plant, the average annual generation can be determined from the generation records for at least the past 5 to 10 years, and preferably for the last 10 to 20 years. The historical generation may require adjustment if generation was affected by planned outages or non-representative water years. A power study (refer to Volume 6) may be required to provide a more accurate picture for the plant.

Similar to Section 6.2.4, the Model supplied for use with Volume 1, Section 4.9 simplifies the input of benefits for each project. The Model accepts standardized energy value forecasts in its

Supporting Tables section. Expected generation benefits can also be inserted in the same area. Refer to the User Materials supplied on the CD-ROM containing the Model.

Value of Energy

The following discussion regarding the value of energy will be of assistance to these users who may not have easy access to pricing information for a first pass evaluation of a proposed project. Similarly, the present value information is not required if the Model is used as present value calculations are incorporated in the Model.

The value of the generation ($/MWh) depends on whether the generation cannot be stored and is run-of-river or can be stored and scheduled to be used during peak periods as peaking energy. Run-of-river generation should be assessed at new baseload unit costs, while generation from units that have storage and can be used for peaking should be assessed at peaking energy costs. For units that have some storage and can be used partially for peaking, the baseload and peaking generation can be proportioned accordingly. Each user of these guidelines should use values for peak and non-peak power costs and proportioning that reflect the actual situation under consideration. For example, if the hydro generation is offsetting three levels of alternative generation costs - gas turbines (10 percent), coal-fired units (50 percent), and non-peak baseload (40 percent) - then the value of generation (VG) computation will consist of three components rather than two as illustrated in these guidelines. If the value of generation ($/MWh) is unknown, values can be obtained from a publication such as "Power Generation Markets Quarterly"[3]. An escalation rate of 5 percent can be used if the escalation rate is unknown.

The present value of the energy generation from the upgraded plant can be determined by applying the present value adjustment factor (PVAF) from Equation 6-6 to the following:

Present Value of

$$\text{Energy Generation After Upgrade} = \text{VG} \times \frac{\left(1 - k^{n}\right)}{\left(1 - k\right)} \times \text{PVAF}, \qquad [6\text{-}7]$$

where

$$k = \frac{1 + e}{1 + i}$$

VG = value of annual generation (peak and non-peak) on the date of commercial operation (MWh/yr x $/MWh),

n = evaluation period in years (15),

e = escalation rate (0.05), and

i = discount rate (0.09), and

[3] *Power Generation Markets Quarterly*, published by the McGraw-Hill Companies, New York, NY.

PVAF = present value adjustment factor.

6.5.2 Capacity

Capacity benefits will be refined in a similar manner to energy benefits (Section 6.5.1). The plant capacity for each upgrading alternative is determined during development of the alternatives.

The value of capacity depends on whether the capacity is considered to be dependable, which is influenced by whether the plant is a baseload run-of-river plant, has storage for peaking, or is a combination of run-of-river and peaking. As with the energy costs, the capacity attributable to each category should be estimated and proportioned. If the value of capacity is unknown, values can be obtained from publications such as "Power Generation Markets Quarterly"[3].

For units installed in years other than 2000, the capital cost escalation rate of 5 percent, as determined earlier, should be used to escalate the cost to a different year of installation.

The present value of the upgraded plant capacity in study date dollar values can be determined by applying the present value adjustment factor (PFAF) from Equation 6-6 to the following:

Present Value of Capacity

$$\text{for Existing Plant After Upgrade} = VG \times k \times \frac{\left(1 - k^{n}\right)}{\left(1 - k\right)} \times PVAF, \qquad [6\text{-}8]$$

where

$$k = \frac{1 + e}{1 + i},$$

VG = value of capacity on the date of commercial operation,

n = evaluation period in years (15),

e = escalation rate (0.0),

i = discount rate (0.09), and

PVAF = present value adjustment factor.

Evaluation of capacity credits varies by utility and the contractual agreements of any system interties. Full credit for any increased capacity may not be allowed if the capacity is not considered dependable, that is, if water is not always available for the plant to operate at maximum capacity. If system criteria are available to determine how much of the increased capacity can be considered dependable, these criteria should be considered in the capacity evaluation. If capacity credit criteria are not available, the full capacity should be credited.

6.6 Other Benefits from Improvement

In addition to the improvement in performance, there may be several other benefits to a life extension and modernization program from a hydromechanical perspective including:

- reduced cavitation repair costs;
- reduced maintenance costs;
- increased value of the asset;
- increase in availability;
- increase in operating flexibility;
- reduced risk and insurance costs; and
- more environmentally friendly equipment.

Each benefit will require assessment for each individual project proposed. Some benefits will be difficult to define financially and may be better treated using a Value Based Management approach if the owner is inclined to use such a system. The use of risk cost benefits in the evaluation of the project/plant benefits will also be dependent upon the owner's requirements. There is provision for risk costs benefits to be incorporated into the Model if desired.

6.7 Input to Life Extension and Modernization Plan

Input to the LEM Plan will include cost estimates into the early stages of the LEM plan formulation in Section 4 of Volume 1 (Tables 4-6 Needs and Opportunities) along with cost and benefits inputs into the Model in Section 4.9 of Volume 1. Additional input will feed into Section 7 of Volume 1 when a revision of costs and benefit estimate will take place for any feasibility study conducted.

7
OPTIMIZATION OF ALTERNATIVES (FEASIBILITY)

7.1 Introduction

Sections 4, 5 and 6 of this volume contribute to the formulation of a Life Extension and Modernization (LEM) Plan for hydromechanical equipment. The information used to formulate the LEM Plan is obtained largely from existing test data and reports.

At the completion of the LEM Plan, the most favourable LEM activities, perhaps with an alternative or two, will be selected to be studied in more detail at the feasibility level. The projects identified in the selected Plan(s) may require more accurate, up to date information in order to:

- verify the technical feasibility by:
  - identifying and optimizing alternative activities (Sections 7.2 and 7.3)
  - selecting the best activities (Section 7.4)
  - undertaking a sensitivity analysis (Section 7.5)
- proceed with the design (Section 8)
- implement the project (Section 8)

Section 7 will outline methods to obtain more detailed information on equipment condition and modernization opportunities.

The additional information required may come from:

- Additional testing (turbine performance testing or individual component testing)
- Additional inspections (with equipment out of service)
- Engineering studies

The information gained from these activities will enable the feasibility of the life extension and/or modernization activities proposed for the plant to be determined.

To acquire testing and inspection information will usually require a commitment from the owner to operate each unit in a non-commercial manner and to take the unit out of service for a period of time. The results of the testing will be valuable, even if they mean that the proposed modernization is not feasible and no further action is taken. The test results will provide a performance base line for future assessments of the plant.

Figure 7-1 describes how the sub-sections of Section 7 contribute to the feasibility assessment of the life extension and modernization activities identified in Sections 4 and 5.

7.2 Testing and Inspection of Hydromechanical Equipment

The decision on which, if any, of the following test procedures to undertake is dependent upon the focus of the feasibility study.

The plant testing methods outlined below should be conducted by competent persons with an in-depth knowledge of the performance capability of the plant. Whilst the penalty for conducting these procedures incorrectly will usually be obtaining poor results, there is the potential for catastrophic failure of the plant and injury to life. The user is therefore cautioned to conduct any plant testing with care.

7.2.1 Non-Destructive Testing[1]

It is highly likely that non-destructive testing has been performed previously on the equipment under investigation. Therefore known problem areas can be targeted for the initial inspection.

The quality, integrity, properties and dimensions of materials and components can be inspected with methods that do not cause damage. The following are nondestructive test methods:

- visual inspection
- liquid penetrant inspection
- magnetic particle inspection
- radiographic inspection
- ultrasonic inspection
- leak testing

[1] US Army Corps of Engineers, "*Detailed Inspection"*, Document ETL 1110-2-346, 30 September 1993

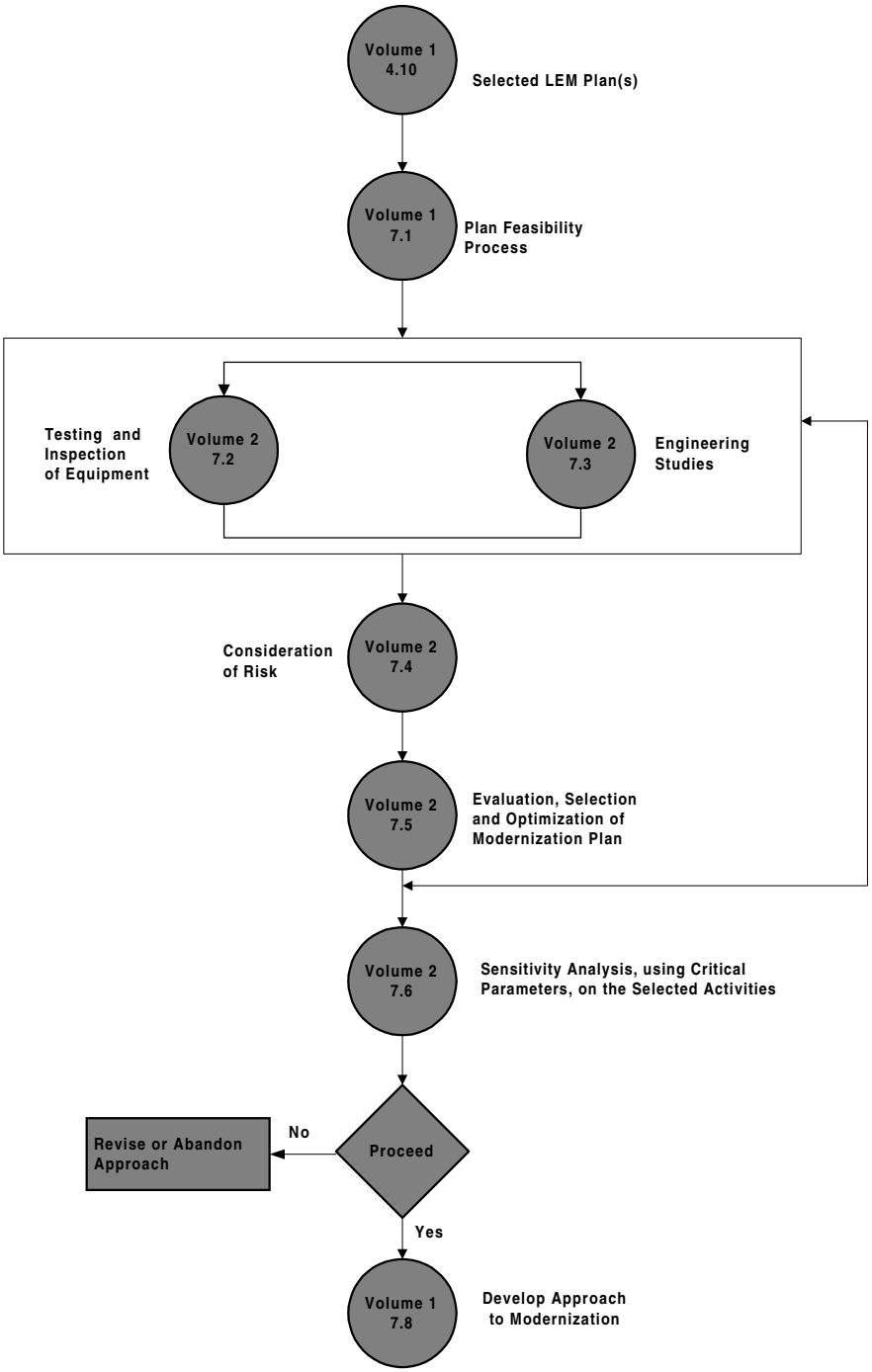

Figure 7-1
Optimization of Alternatives

For plant hydromechanical equipment, nondestructive methods can be applied for the following inspections/investigations:

1. runner cracking
2. cavitation, erosion or corrosion weld repair on runner, spiral case, wicket gates and other turbine components
3. thickness of pressure vessels (spiral case, governor hydraulic pressure units)
4. cracking on other steel components (shaft, bearing, spiral case, babbitt)
5. leak testing of governing hydraulic systems and turbine emergency shut-off devices (turbine inlet valve, wicket gates)

Weld

Virtually every inspection method available has been used to examine welds: visual, magnetic particle, liquid penetrant, ultrasonic, destructive testing and radiographic – X-rays and radio-isotopes. Table 7-1 lists the advantages and disadvantages of various inspection techniques. The method and extent of the inspection vary with the nature of the work and the criticality of certain joints. The following factors should be considered in selecting nondestructive methods for weldments:

- materials to be used
- joining process
- geometry of material
- possible or expected defects and their orientation

Some weldments may require combinations of two or more inspection methods to provide adequate evaluation.

Table 7-1
Uses of Various Non-Destructive Inspection Techniques

	Magnetic Particle	Penetrant	Ultrasonic	X-ray
When to use	Suitable for detecting surface and near surface flaws, cracks, porosity, nonmetallic inclusions and weld defects	Used to locate surface cracks, porosity, laps, cold shuts, lack of weld bond, fatigue and grinding cracks	Pulse-echo used to find internal defects, lack of bond, laminations, inclusions, porosity, grain structure; resonance used primarily for thickness gaging and laminar flaws.	Detection of internal flaws and detects; weld flaw detection includes cracks, seams, porosity, holes and inclusions, checking assemblies, lack of bond and thickness variations.
Where to use:	Used on all types of ferro-magnetic materials - tubing, piping of any size, shape, composition or state of heat-treatment; used for in-service testing for fatigue cracks	Used on all metals, glass, ceramics, castings, forgings, machined parts, cutting tools, and for field inspection	Used on all metals and hard nonmetalic materials - sheets, tubes, rods, forgings, castings - in field and production testing. In-service part testing for aircraft and marine inspection.	Used on forgings, castings, tubing, formed metal parts, welded vessels; used in field testing of welds, corrosion surveys and assemblies.
Reasons to use:	Simple in principle, easy to perform, portable for field testing, fast for production testing; method is positive and cost is economical.	Simple to apply, accurate, fast, low initial cost and per test copy, easy to interpret results, no elaborate set-up required.	Fast and dependable, easy to operate. Lends itself to automation, results of test immediately known, relatively portable, highly accurate and sensitive.	Provides permanent record on file, better on thin sections; often higher sensitivity; fluoroscopy techniques available with adjustable energy level.
Limitations:	Parts must be magnetic; requires demagnetizing after tests. Power source its needed, and parts must be cleaned before finishing.	Limited to surface defects; surface cleanliness required.	Resources contact or immersion of part to be tested, interpretation of defects requires training.	Higher initial cost, power source required, radiation hazard; trained technicians required.

Cracking

To identify cracks on Francis, Kaplan, propeller, and pump-turbine runners, the following two NDT procedures are most commonly used:

a. Dye penetrant - first level inspection

b. Magnetic particle - more accurate

Because of the high cycle stresses on Pelton runners, it is important the cracks are identified earlier, therefore magnetic particle inspection is used more often.

Ultrasonic and radiographic methods of inspection are rarely used for maintenance inspections and inspections for any type of used equipment. These methods are usually applied to new equipment when weld and casting quality is being checked and manufacturing defects need to be identified (e.g. porosity).

Cracking and Skin Thickness of Pressure Vessels

In a hydro plant, testing of the integrity of the spiral case is rarely performed unless an obvious problem (cracking, leaking behind spiral case) has developed. Ultrasonic methods are needed to determine the relative thickness of areas on the spiral case and other pressure vessels.

7.2.2 Turbine Performance Testing

General

Turbine performance tests determine the turbine efficiency relative to turbine output or flow. Since turbine output is also dependent on the headwater (inlet pressure) and tailwater conditions, these parameters are measured in addition to turbine output and flow. Turbine performance curves are derived from individual test points over the full range of turbine operation. Typical ranges are:

- 40 to 100% wicket gate opening for Francis turbines,
- 25 to 100% wicket gate opening for Kaplan turbines.

Test points are selected between minimum and maximum output, and inlet pressure, tailwater, turbine output and flow are measured for each test point. To minimize the influence of any oscillation or measurement errors, multiple readings (20 or more) can be taken over a 1 minute to 5 minute interval for each test point if data are being manually recorded. Computer interfaced data acquisition systems can be used to take multiple readings over a 20 to 30 second interval. The readings taken for a single test point are averaged and referred to as a test run.

Evaluating the performance of the existing turbine can be simplified by comparing the present maximum output with that of the original unit. Since turbine output is a function of the head acting on the unit, the net head during the test must also be determined. Turbine discharge would be most helpful in determining the existing performance; however, because of the difficulties in measuring turbine flow, as discussed later, flow measurement may not be justified.

Performance Test Codes

There are two test codes used to provide a common basis for reporting turbine performance:

- International Electrotechnical Commission (IEC) Code, Publication No. 41

- American Society of Mechanical Engineers (ASME) Power Test Code PTC 18

The codes are similar except that ASME PTC 18 uses conventional head units, H, and IEC Code, Publication No. 41 uses the concept of specific hydraulic energy, gH.

The use of a test code to measure and report turbine performance provides a basis for interpreting results obtained and for comparing the effectiveness of any modernization works conducted.

Turbine Output Measurement

Turbine output is often measured indirectly from the generator output using the existing unit watthour meter or a precision wattmeter and dividing the generator output by the generator's efficiency in the following formula:

$$P_{Turbine} = \frac{P_{Generator}}{Efficiency_{Generator}} \qquad [7\text{-}1]$$

Generator output using the unit watthour meter is determined by maintaining a fixed wicket gate position and unity power factor, and recording the beginning and ending watthour meter readings over a period of time. The generator output is calculated from the watthour difference divided by the elapsed time. Recent calibration of the watthour meter will ensure accurate and valid results. The generator efficiency in the above equation can be determined from the data in Volume 3 of these Guidelines

A more accurate method for measuring generator power could be obtained using the two-wattmeter or three-wattmeter method, as described in IEC Code, Publication No. 41 or Institute of Electrical and Electronics Engineers (IEEE) Standard 120-1955. However, the increased accuracy of these test methods is not usually warranted for the feasibility level studies presented in these guidelines.

Head Measurement

Gross head is usually defined as the difference in elevation between headwater level of the plant intake and tailwater levels. Gross head is normally determined from staff gauges mounted on the powerhouse or dam structure or permanent level gauges with readout in the powerhouse control room. If staff or level gauges are not installed, measurements from headwater and tailwater levels to a known elevation such as the intake and draft tube decks can be made.

The actual head acting on the turbine available to do work is referred to as turbine net head. The ASME PTC 18 Code and the IEC Code, Publication No. 41 define turbine net head as the difference between total head at the turbine inlet and total head at the outlet of the draft tube. Net head equals gross head minus trackrack, intake, penstock and draft tube exit losses.

In calculating net head, the inlet pressure, P_{g1}, can be measured by a precision pressure gauge, pressure transducer, manometer, or dead weight manometer. Flow velocity can be determined

from either direct discharge measurement or from turbine discharge estimated from the turbine performance curves.

Discharge Measurement

Turbine discharge measurement is difficult, time consuming, costly, and subject to inaccuracies because direct measurement and calibration is impractical due to the high flows and volumes involved. Several recognized indirect measurement methods of flow measurement have been developed which are summarized in Table 7-2.

While the flow measurement methods adopted by the IEC and ASME provide measurement accuracies in the order of 1% under ideal conditions. the following simplified flow measurements can be used to determine the actual capability of existing turbines:

- For low head run-of-river power plants, the approximate power plant discharge can be determined from nearby gauging stations in the river, if these values are considered reliable. However, the best USGS gauges are only 5% accurate. Therefore this method of flow measurement for establishing turbine efficiency is very rough.
- For medium and high head plants, turbine discharge can be determined from the available turbine efficiency curves less reductions for the effects of deterioration discussed in subsequent paragraphs.

The flow measurement accuracy using these simplified methods is approximately ±5%. Established code flow measurement methods would be necessary if greater precision is required.

Comparison of Turbine Output

Comparing the present maximum turbine output with the original output can indicate the extent turbine performance has deteriorated and can be used to estimate present turbine efficiency. Since turbine tests are conducted under the headwater and tailwater conditions existing at the time of the test, the actual net head at the time of the test will likely be different from the rated or maximum net head. Therefore, test results must be adjusted for comparison with the turbine output at the design heads. The relationships to adjust discharge and output for different heads are the following:

$$P_{\text{original head}} = P_{\text{actual}} \times \left[\frac{H_{original}}{H_{actual}}\right]^{1.5} \qquad [7\text{-}2]$$

$$Q_{\text{original head}} = Q_{\text{actual head}} \times \left[\frac{H_{original}}{H_{actual}}\right]^{0.5} \qquad [7\text{-}3]$$

The accuracy of power and flow extrapolations using the above relationship decreases as the difference in heads increases; therefore, the conversion should be limited to head differences

of ±10%, particularly for Kaplan and propeller turbines. The following procedure can be used to convert the turbine test results for comparison to the original output and head.

The amount that turbine output has been reduced can be determined by the following:

$$\text{Turbine Output Reduction} = \left(1 - \frac{ActualAdjustedTurbineOutput}{OriginalTurbineOutput}\right) x\ 100 \qquad [7\text{-}4]$$

Actual Test Results	Adjusted in Power for head	Adjusted Turbine Output	Original Turbine Data
Turbine Output, kW __ x	$(Hn_o/Hn_a)^{1.5}$	= _____	vs _____
Net Head, ft (Hn_a) _____			(Hn_o) ___

An example follows to demonstrate the principle.

Table 7-2
Flow Measurement Methods for Turbine Efficiency Testing

Type	Methodology	Advantages	Disadvantages	Accuracy Range of Usual Values	Equipment to be installed in Penstock or Canal	Approx. Downtime Required for Installation/ Removal
Acoustic	Measurement of transient time of ultrasonic pulses across a penstock.	No installation required for repeat tests	Requires a straight run of pipe	±1.0% to ±2.0% 2 crossing planes with 4 paths each	16 acoustic transducers for 2 planes	1-2 weeks installation
Current Meter	Series of current meters set on a frame (fixed or moving) collects point velocities to establish a velocity profile and hence flow rate.	Can be used on almost any plant.	Requires straight length of pipe at least 25 diameters long and many measurement points.	±1.0% to ±2.0%	1 frame	1 week to install 2 days to remove
Dye Dilution	Change in dye concentration measured between 2 points with flow derived from this data.	Very suitable for small hydro projects.		±1.0% to ±2.0%	Injector in intake and collection rack in draft tube	2 days
Pitot Tube	Point velocity method using pitot tubes to measure the difference between stagnation and piezometric pressures at a point.		Requires straight length of pipe 20 diameters long before pitot tube. Large number of test points required. Careful measurement techniques also required.	±1.5% to ±2.5%	Flange for pitot tube	
Pressure-Time (Gibson)	Measurement of pressure difference between two sets of pressure taps in a penstock and then application of Newton's second law to derive velocity.	No apparatus is installed inside the penstock.	Requires externally accessible straight length of pipe at least 9 m or 2 diameters long. Penstock and spiral case subjected to pressure waves.	±1.5% to ±2.3%	Piezometer taps in penstock	1-2 days
Salt Velocity	Measurement of transit time between two electrodes of a brine solution in a penstock.	Successfully used in both turbine and pump tests.	Requires straight length of pipe at least 8 diameters long. Large amount of hardware to be secured in penstock. May not meet environment regulations.	±1.0% to ±1.5%	Injector valve frame, electrodes and turbulator	2 weeks to install 1 week to remove

Type	Methodology	Advantages	Disadvantages	Accuracy Range of Usual Values	Equipment to be installed in Penstock or Canal	Approx. Downtime Required for Installation/ Removal
Thermodynamic	Application of conversation of energy principle. Water temperature is measured both upstream and downstream of the turbine.	No physical flow measurement is required. Can give very accurate results.	Outside thermal influences such as sun and auxiliary cooling may affect results. Not suitable for low head plants (requires >100 m).	±0.6% to ±1.0%	Probes in penstock and rack in draft tube	4 days
Venturi Meter	Measurement of differential pressure across a venturi tube is translated into flow using a calibrated curve.		Requires 8 diameters of straight pipe before and 3 diameters after the meter. Head loss is caused by permanent installation and temporary installations are expensive.	±1.0% to ±1.5%		
Volumetric	Measures changes in reservoir volume over a period of time.		Requires regular formed reservoir to measure volume. Reservoir must be captive as river inflows and evaporation are unknown. Requires hours of fixed gate operation to achieve one test point.	±1.0% to ±2.0%		
Weir	Weir is placed in the tailrace with flow calculated from height of water above weir.	Weir is usually a permanent structure.	Relatively inaccurate.	±1.7% to ±3.0%		

The original turbine efficiency (η_{orig}) is based on original records or calculated from the original head, power, and flow, using the formula 7-5 in the following paragraphs. Comparison of the original and present turbine performance must be made at the same wicket gate opening to ensure that the same conditions are compared.

Example of Comparison of Turbine Output

A turbine was tested with results as follows:

Actual output, P_{act} = 10,200 kW
Net head, Hn_{act} = 52.5 ft

The original turbine output and net head were:

Original output, P_{orig} = 10,000 kW
Original head, Hn_{orig} = 50 ft
Original Flow, Q_{orig} = 2630 CFS
Original efficiency, η_{orig} = 90% (using Equation 7-5)

∴The adjusted turbine output, P_{adj}, can be determined from Equation 7-2:

$$P_{adj} = P_{act}\left(\frac{Hn_0}{Hn_a}\right)^{1.5}$$

$$= 10{,}200\left(\frac{50}{52.5}\right)^{1.5}$$

$$= 9{,}480 \text{ kW}$$

and, the Turbine Output Reduction can be determined from Equation 7-4:

$$\text{Turbine Output Reduction } (\%), \Delta\eta = \left(1-\frac{P_{Adj}}{P_{orig}}\right)\cdot 100$$

$$= \left(1-\frac{9480}{10000}\right)\cdot 100$$

$$= 5.2\%$$

Actual Efficiency of the Turbine = $\eta_{act} = \eta_{orig} - \Delta\eta = 90\text{-}5.2 = 84.8\%$

Therefore, the 5.2% reduction in turbine output could be restored by rehabilitating the runner, runner clearance, and other hydraulic components. Additionally, the present turbine efficiency can be approximated by the following:

The accuracy of this method is limited by the accuracy of the unit output measurements and any changes in generator efficiency between the tests. However, by comparing the existing efficiency with the original or modern turbine efficiency, this simple procedure can provide a rough estimate of turbine upgrade potential.

Calculating Turbine Output

Turbine output is a function of the head acting on the turbine, flow through the turbine, and turbine efficiency, and can be calculated from the following formula, shown in both US Customary and metric units:

$$P_T = 0.0846 \times Q \times H_n \times \eta_t \text{ ,} \quad P_T = 9.8 \times Q \times H_n \times \eta_t, \qquad [7\text{-}5]$$

(US Customary) (SI Units)

where

P_T = turbine output, kW
Q = turbine discharge, cfs (m^3/s),
H_n = net head, ft (m), and
η_t = turbine efficiency, percent /100

Index Test

An index test is a test method which determines the turbine efficiency relative to the peak efficiency. Details of the test procedure are described in both ASME PTC 18 Code and IEC 41 Code. While the index test provides only a relative and not absolute measure of turbine efficiency, an index test can determine the absolute change in efficiency if a previous index test has been performed on the turbine. The index test results can be compared to the previous data to determine the reduction in turbine efficiency. During a plant modernization, index tests of each unit can be used to optimize plant dispatch and operating efficiency to maximize energy production under all flow conditions. If modernization of the turbine is not warranted at this time, the index test can form the basis for future comparisons.

For Kaplan turbines, index test results can be used to accurately determine the optimal runner blade and wicket relationship whether or not previous tests have been performed. Therefore, an index test is recommended for all Kaplan (adjustable blade) turbines whether or not turbine modernization is considered.

7.2.3 Governor Performance Testing

The general objectives of governor testing are to:

- Protect the public, personnel and the plant
  - The magnitude of the hydraulic transient or water hammer that occurs during rapid load changes or load rejection is largely dependent on the full rate opening and closing wicket gate timing for Francis and Kaplan turbines and the needle valve opening and closing times on Pelton turbines. ***Incorrect operation of the governor in this regard can lead to catastrophic failure of the spiral case or penstock.***
- Allow adjustment and calibration
  - Optimization of unit performance within a power system in isolated conditions will be achieved along with the ability to synchronize smoothly.

Unit uprating, addition of outlet works or turbines to existing penstocks or loss of original test data all necessitate a thorough water hammer and hydraulic transient study. Load rejection tests should also be performed to verify the study results and determine the correct full rate wicket gate/needle opening and closing times for safe operation.

The US Bureau of Reclamation has a published procedure for testing governor performance which can be used as an example. It is available from their website at http://www.usbr.gov/power/data/fist_pub.htm.

Governor testing and calibration/adjustment should only be conducted by competent persons who are familiar with the required procedures. If the procedures are not followed correctly there is the potential for catastrophic failure. If there is any doubt an expert should be consulted immediately.

7.2.4 Turbine Inlet Valves (TIV) Testing

Turbine inlet valves (TIV) are rarely subjected to extensive tests to measure leakage or headlosses. TIV replacement is uncommon and testing is not justified unless TIV replacement is included as part of a larger modernization project. However, periodic testing of valve closing times is a necessary part of plant maintenance programs.

Leakage tests provide measurable evidence of a perceived increase in valve leakage over time and therefore may be valuable when a TIV life extension or modernization project is being considered because isolation of the units is unreliable without the closing of upstream gates.

Head loss tests provide useful information for a large plant modernization project where plant efficiency improvements are the driving force. The following provides details on the more extensive tests that can be performed on the TIV.

Leakage

Valve leakage is measured with the valve in the closed position, upstream pressure acting on the valve and the downstream side dewatered. Leakage rates are generally a function of the head acting on the valve; however, maximum leakage often does not occur at maximum head. Valve leakage should be measured at a head within 20% of the design head and is determined by measuring the accumulated water over a period of time. The measured leakage can be compared against the following leakage rates for new and used valves illustrated in Table 7-3.

Table 7-3
Leakage Rates for TIVs

	Butterfly Valve	Spherical Valve
Leakage in new condition	0.005 cu ft/min per ft of valve diameter 0.5 P/min per m of valve diameter	A few drops
Acceptable leakage in used condition	0.02 - 0.03 cu ft/min per ft of valve diameter	0.02 cu ft/min per ft of valve diameter
	2.0 - 3.0 P/min per m of valve diameter	2.0 P/min per m of valve diameter

If valve leakage exceeds these quantities, the valve seals should be replaced to minimize water loss and prevent progressively increasing seal damage.

Operation

The closing time of the inlet valve should be checked to ensure appropriate closure rate. Because of the hydraulic characteristics of the valve (head loss versus opening), when the valve is closed against flow, a significant decrease in flow does not occur until the valve is about one-half closed. Similarly for hydraulic transients, the valve closure time may be two or three times the wicket gate or the injector needle closure times. The initial test of closing time should be conducted under the no-flow condition with the wicket gates closed and locked. However, the closing time against flow can be as little as half the no-flow closing time. Provided the valve and valve control system were designed for closure against flow and that closure against flow has been previously tested, the valve closure test under the full turbine discharge conditions may be performed by the following procedures:

1. Load the turbine to 25% load and perform a load rejection test to determine the turbine wicket gate closing time, pressure time, and unit speed time.

2. Operate the turbine at 25% load by limiting the turbine output with the load limiter.

3. Close the inlet valve against 25% turbine flow and measure the valve closing time and pressure rise. As the valve closes, monitor the unit output and when the load approaches 0, trip the unit breaker and shut down the turbine unit.

4. Compare the test results of the wicket gate and valve closure tests. If the pressure rise during the valve closure is less than during the turbine shutdown, repeat Steps 1, 2 and 3 for increasing loads in steps of 50%, 75% and 100% load.

Ideally, successful valve operation under full flow condition should be confirmed; however, detailed engineering review prior to the test is warranted. For very high head units, a full flow

test may not be performed because of the significant energy dissipation and the concern that equipment life could be reduced.

If the existing inlet valve is to be used with an uprated turbine having higher flow or head, the dynamic torque on the valve disc or rotor will increase and the operating forces may increase above the capacity of the operating system. Stress levels in the valve can also be affected. Evaluation of the valve by the manufacturer or a valve specialist should be performed to confirm that the valve components are not overstressed. Emergency closure criteria in particular should be evaluated for the new head and flow conditions. Section 4 contains information on assessing valve condition.

Head Loss

Another performance characteristic of inlet valve is the head loss or energy loss across the valve. Head loss attributed to the inlet valve can be measured by comparing the upstream and downstream pressures using a differential pressure gauge or transducer at the maximum unit discharge. Because of the relatively low head losses in valves, pressure measurements may not be justified for the accuracy required for the feasibility level modernization studies. Therefore, head loss across the valve may be estimated as described previously in Section 4.5.7.

7.2.5 Testing of Other Turbine Components

The testing of other turbine components such as stay vanes, spiral case, runner seal rings, stationary wear rings, etc. is usually conducted using the non-destructive techniques outlined in Section 7.2.1.

7.3 Engineering Studies

Engineering studies are used to bring the required information together to make rational decisions on the feasibility of specific hydromechanical improvement activities. The process covers:

- Assessment of previously gathered information (Volume 2, Sections 4 and 5)
- Assessment of results of inspection and testing (Volume 2, Section 7.2)
- Power Studies (Volume 6)
- Analysis of effects of proposed modernization on overall plant (Volume 2, Section 5.9)
- Buildability analysis (Volume 1, Section 7.4)
- Value engineering (Volume 1, Section 7.4)
- Improvements in assessment of costs (Volume 2, Section 6.3)
- Improvements in assessment of benefits (Volume 2, Section 6.5)
- Selection of best hydromechanical equipment modernization (Volume 2, Section 7.4)

Other engineering studies, such as a CFD analysis of the turbine, may not be required until the project implementation stage due to their high cost. The use of studies, such as CFD analysis, at the feasibility level may be necessary if the modernization activity under analysis is of a large enough size to warrant it, e.g. multiple runner modernization. Conversely, if the proposed project viability is determined to be sensitive to the outcome of a CFD analysis, it may be that the project should not be pursued. The iterative nature of the LEM planning process is intended to optimize outlays and not to commit large amounts to studies which should not be conducted until preliminary studies indicate that the project proposed has merit.

7.4 Risk Considerations

Risk management is the ability to balance risks with the potential gains by making wise decisions.

As part of the feasibility study process, it is advisable to assess the risks associated with each option being assessed. Each risk, along with the potential mitigation available, can be identified. Risk areas to be considered, from a purely hydromechanical perspective, are included in the following box:

AREA	RISK
Technical and technological	• Proposed modernization activity does not work • New equipment does not meet performance levels • Technology changes make modernization obsolete • Inadequate assessment of condition • Incorrect designs and inadequate quality assurance (QA) • Once work is initiated, more is identified
Construction	• Cost overruns • Delayed schedule, longer outages • Consequential damage • Contractor unfamiliar with specific work • Poor estimates of cost
Environmental	• Impacts on land/water due to construction • Pollution and spills
Operating	• New operation rules not written • New operation methods not attainable • Operation changes not acceptable by external stakeholders • New operation does not achieve expected gains

The user should examine all areas above with particular regard to the hydromechanical activities resulting from work associated with this Volume.

The risks identified by this process need to be examined for their acceptability. If some risks are apparently unacceptable as they stand then the mitigation available to reduce the risks to acceptable levels has to be identified. If the cost of mitigation is uneconomic then the risks are confirmed as unacceptable and the project or activity is not feasible. If the mitigation can reduce risks to an acceptable level at an economic price, then the costs of the mitigation will be included in the financial evaluation conducted during the feasibility study.

Volume 1, Sections 2.3.2, 4.6 and 7.5 all deal with risk identification and management and should be used as a reference. More detailed evaluation and management of risk issues is beyond the scope of these Guidelines.

7.5 Evaluation, Selection and Optimized of Modernization Plan

Modernization activities (opportunities) were identified, assessed and screened as part of Section 5 of this Volume and Volume 1, Section 4. This provided a "Plan" for hydromechanical equipment in the context of the overall plant. The next stage in the process was to evaluate the proposed activities in more detail and to optimize the activities. To do this required additional testing and inspection of equipment (Section 7.2), engineering studies (Section 7.3) and the identification and evaluation of the risks associated with each proposed activity or project (Section 7.4).

With the results of the work associated with Sections 7.2, 7.3 and 7.4, all options explored during feasibility can now be evaluated. This will enable a final modernization plan to be selected and optimized before undergoing a final sensitivity analysis (Section 7.6).

In some cases, the additional data, gathered during the feasibility process, will shed new light on the whole process. The option that moved forward from the formulation of the Modernization Plan may have to be reconsidered. For example, if an item of equipment is more seriously deteriorated than initially thought, or its performance is worse than originally measured, the cost of replacement or repair may be higher than expected, or the case for modernization may become more attractive.

Cost and benefit information should also be reviewed at this point to feasibility level (Refer to Volume 1, Section 7.6 and Volume 2, Sections 6.4 and 6.5) to enable selection of the appropriate modernization plan.

7.6 Sensitivity Analysis Using Critical Parameters of Costs and Benefits

An integral part of the project analysis is conducting a sensitivity analysis on the selected modernization plan using parameters which will be critical to the selected modernization project's success. These parameters can be broken into two categories:

- Costs
- Benefits

Some of the parameters discussed will be applicable in some cases and not in others. For example, delays in construction which extend a unit outage may have consequential costs in

some cases but, in other cases, where the plant may be water constrained, an extended outage will not incur any additional lost production costs.

The project under consideration may be a distinct project or part of a program of projects to modernize a plant. The sensitivity analysis for the project may form part of a larger sensitivity analysis. Usually, however, the sensitivity analysis will be for the modernization process as a whole.

The sensitivity analysis for each identified project is conducted within the electronic template used in Volume 1, Section 4.9. The user guide supplied with the template describes how to conduct the sensitivity analysis within the template. Some of the parameters discussed below will be combined before insertion into the template.

The range used in the analysis for each parameter will depend upon the individual circumstances of each owner and of each plant. These Guidelines will not attempt to specify any ranges to be used.

The parameters examined could be combined in a multitude of scenarios. These Guidelines will not attempt to distinguish between the possible scenarios as each individual project and plant examined will have its own particular circumstances at any given time.

7.6.1 Costs

Cost parameters to be assessed for sensitivity analysis include:

- Engineering costs
- Licensing costs
- Construction costs

Engineering Costs

Engineering costs include those associated with the detailed engineering design following the decision to proceed.

Licensing Costs

Licensing costs include all those associated with the relicensing process applicable to the project under consideration. This can be a particular area of concern due to the "open ended" nature of the process. Refer to Volume 1, Section 6 for details of the relicensing process.

Construction Costs

Construction costs include all costs associated with the construction process. These may include cost associated with:

- Claims for extras by the contractor(s)
- Consequential costs from the contractor's claims, e.g. other contractor claims, legal costs, administration costs.
- Delays to the completion of the project works which could incur costs to the owner, e.g. additional administration costs, cost of additional lost production.
- Escalation (if the project is over an extended period).
- Interest rate movements.
- Exchange rate movements

7.6.2 Benefits

Benefit parameters to be assessed for a sensitivity analysis include:

- Capacity
- Efficiency
- Availability
- Value of energy
- Fuel cost

Capacity

The expected capacity improvement from the project is well defined at this stage. A sensitivity analysis of capacity will focus on the economic effects of a short-fall in capacity from the projected valves.

Efficiency

Sensitivity of project economics to efficiency values can be assessed using the same analysis method used for capacity.

Availability

A sensitivity analysis of availability is dependent upon the individual plant under consideration. Availability, for some plants, is not an issue due to system requirements, i.e. its use is flexible or it has water constraints. In the changing market of today, however, availability will be extremely important. Each owner will have to quantify how it wishes to treat availability financially as a benefit. The value to an owner of a flexible plant that is consistently available for service will depend upon the owner's circumstances and market arrangements. Obviously, however, the greater the availability of the unit the greater the opportunity to take advantage of the market.

Value of Energy

The expected value of energy in the future has been predicted by the owner in the electronic template used in Volume 1, Section 4.9 but a sensitivity analysis of the prediction may be required. It is difficult to specify a percentage range to assess but, in an open market, this could be high on a short term basis. Each owner will have its own particular situation.

Fuel Cost

Fuel, which in the case of hydro plants is water, normally has costs. These are often related to water usage, storage or capacity costs. The sensitivity analysis would consider possible changes (increases) in water usage fees.

8
IMPLEMENTATION OF MODERNIZATION PLAN

8.1 Introduction

Previous sections of this Volume have provided information for the user to identify, evaluate and select an appropriate life extension and modernization plan for hydromechanical equipment and confirm the feasibility of selected activities. Section 8 assists the user in formulating a general plan of action and implementing this modernization plan.

Figure 8-1 outlines the steps involved in preparing proposed life extension and modernization activities for implementation.

8.2 Design and Engineering Studies

8.2.1 Turbine Runners

Design and engineering studies for turbine runners fall into two categories:

- Physical model testing
- Theoretical modeling

Physical Model Testing

Hydraulic flow conditions in a hydraulic machine are generally too complex to be studied exclusively by theoretical methods. As a result, operation of a physical unit is the only reliable method available which can:

- confirm the hydraulic profile obtained by mathematical methods
- determine the characteristics of a machine under all operating conditions

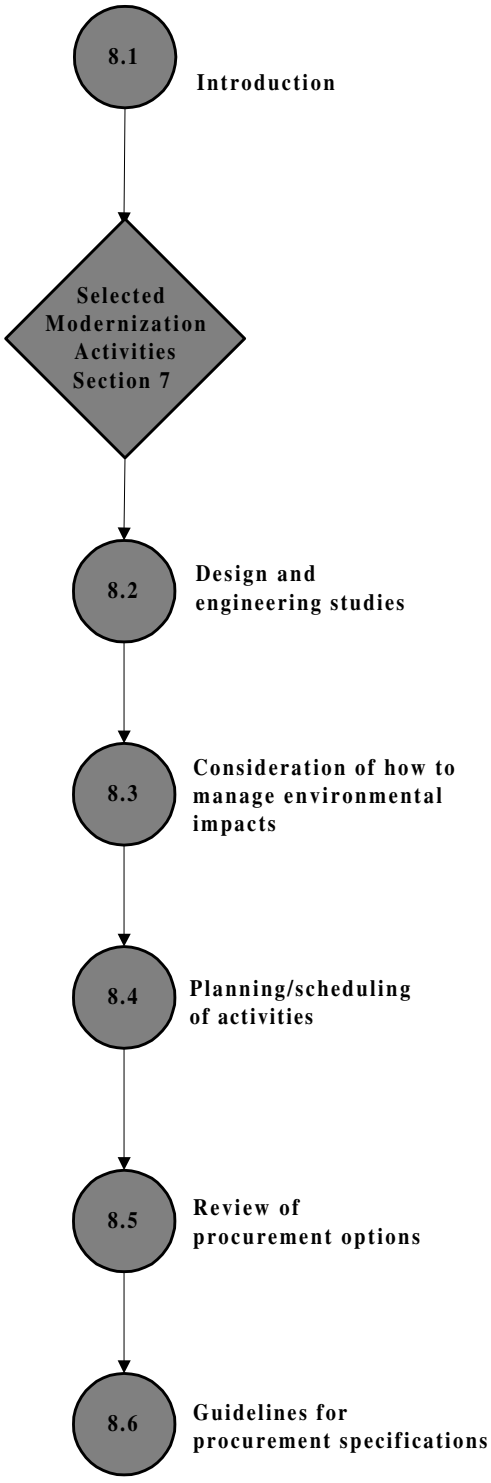

Figure 8-1
Implementation Process

- study the optimal setting of the unit to avoid cavitation damage, or to reduce it to acceptable levels (Note: the setting of an existing unit usually cannot be changed; however, the model tests can still be used to assess output limits which will give acceptable cavitation performance),and
- evaluate the static and dynamic forces acting on the different elements.

The knowledge gained from existing plants forms an important baseline source of information. Hydraulic machines, however, are generally designed for very specific site-related conditions and each machine is unique because of operating conditions and dimensions. Therefore, previous unit operating experience usually cannot be completely relied on to predict the performance of a new or modernized unit.

Since existing prototype experience normally does not provide the broad spectrum of design data required, reduced scale models are the only practical and economical method which can verify the performance characteristics of a hydraulic machine. The model test results provide the engineering feedback necessary to improve the theoretical design before the prototype is constructed.

Testing of scale models is a practical and economic method to determine the expected performance of a hydraulic machine. Model test results provide the feedback required to improve the theoretical design before constructing the final product.

Physical model tests, in the context of life extension and modernization, are used for the following reasons:

- Confirm that the hydraulic design of the hydraulic machine has been optimized for site conditions and verify that a prototype built to this design is capable of meeting contractual requirements for efficiency, power output, cavitation behavior, etc.
- Develop improvements in existing machines more economically than by experimenting with the prototype.

A typical example of the results of model testing is shown in Figure 8-2, where the expected performance in pump mode curves of the pump/turbine (resulting from model testing) are drawn and compared with the guaranteed points.

Confirmation of Hydraulic Design

From the Owner's viewpoint, model testing has always been the traditional method used to verify that contractual requirements, in particular, for efficiency and power output are met. A typical example is shown in Figure 8-1, where the expected performance curves of the pump-turbine prototype in the pump mode (resulting from the model tests) are drawn and compared with the guaranteed points. During the witness tests of the model, several points were checked to confirm the preliminary results.

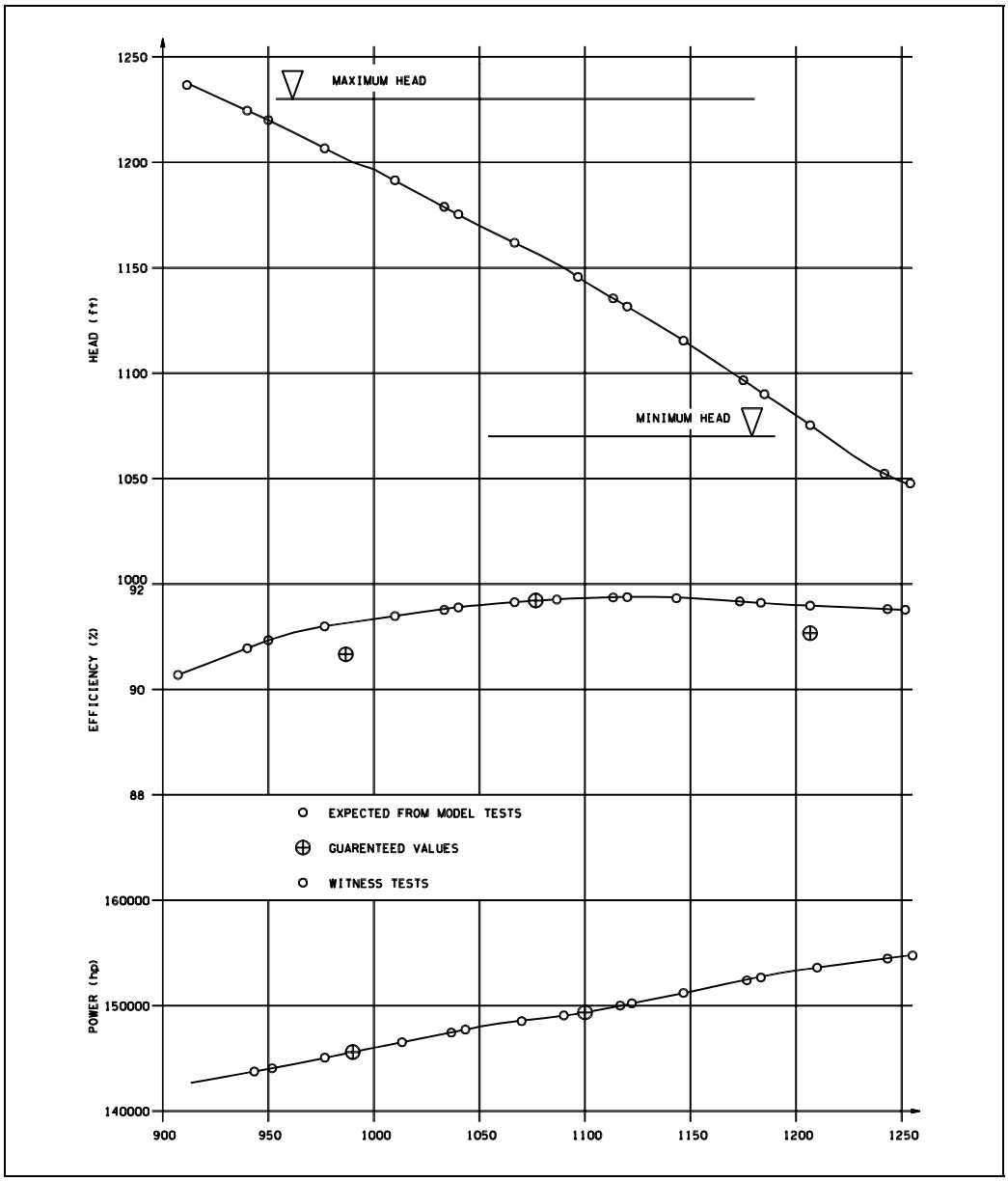

Figure 8-2
Comparison between Expected Performance Curves and Guarantee Points
Source: (*Guide for Hydraulic Machinery Model Testing*) EPRI, Palo Alto, CA 1988. Report AP-5876

Evaluation of cavitation performance and verification of prototype cavitation guarantees are also carried out during model testing by observing the cavitation characteristics under various operating conditions. Confirming the model cavitation characteristics is essential for ensuring acceptable prototype cavitation performance. Severe prototype cavitation damage results in performance deterioration and the need for major unit outages for repairs.

Economic Justification for Model Testing

The cost of model testing needs to be weighed against the potential gains resulting from avoided operational problems and downtime along with increased inefficiency and output. To illustrate this point, an example of an evaluation appears in the box below for a replacement runner.

Example
A 100 MW unit typically operated 5,000 hours per year with revenues of 4 cents/kWh. Gross revenues from the unit per year would be:

100,000 kW x 5,000 h x $0.04/kWh = $20M

New efficiency improvements of several per cent are typical for runner upgrades and, if average downtime can be lowered due to improved cavitation performance, it would be reasonable to expect a 1% improvement in revenues from the unit over and above the increase expected if no modeling was used.

A 1% increase in revenue per annum = $20,000,000 x 0.01
= $200,000

At an 8% discount rate over 20 years, the present value of the increase in revenue of 1% is $1.99M which is much greater than the cost of modeling. Model costs for this unit would be in the $500,000 to $700,000 range.

It must be recognized that model tests will extend the time necessary to procure a new turbine runner (see Section 6.3.1) and this must be considered when specifying model tests.

Contractual Aspects

The owner and manufacturer have different perspectives on the requirement for model testing. Model testing is essentially a risk management technique which mitigates the changes of the investment in a new runner being unsuccessful. The problem lies in the fact that the risks being mitigated for each party may appear similar but are actually quite different.

The owners may take the approach that the use of a performance specification will bring it the best result by requiring certain improved performance characteristics be met. Using this type of specification will leave the decision to utilize model testing with the manufacturer as it bears the risk of not complying with the specification requirements.

From the manufacturer's perspective, the chance to reduce its bid price to secure the contract by omitting model testing may be worth taking. The risk posed of contractual penalties being imposed for non-performance may be smaller than the incentive of securing the contract.

Whilst, from a contractual and legal viewpoint, the use of a performance specification with associated penalties for non-performance appears to be straightforward there are important issues being overlooked:

- If legal action is required it is usually protracted and expensive and the monies recovered, in some cases, will not cover the generation value already lost and that which will be lost over the next 40 to 50 years. Penalties may only be a proportion of the runner price and may not be related to future revenues.
- The manufacturer may have no incentive to improve the upgraded runner's performance beyond that specified and will usually be satisfied with achieving the minimum performance requirements set out in the specification. Therefore the potential for performance improvements over and above those specified may be lost.

The owner can overcome these potential problems by specifying that model testing shall be conducted, except for small turbines, and making it a competitive, specific contract item. The owner is best placed to the extent, if any, of model testing it requires and should take the initiative rather than allow the manufacturer to decide.

Omission of Model Testing

If it is proposed to forego model testing on the basis that a similar model has already been tested, the following criteria should be considered:

- The model already tested must have dimensions greater than the minimum prescribed. Requirements for the minimum testing head and Reynolds number and, in some cases, Froud number, Weber number, etc. should be fulfilled.
- The specific speed of the tested model should not differ by more than ±5% with respect to the proposed upgraded machine.
- The tests performed on the existing model should be successful and completely cover the operating range and other requirements for the proposed upgraded machine.
- Complete Model Test Reports should be available and Witness Tests should be performed.
- Model Test Reports should be available to the Owner to enable the Owner to judge if the above conditions are fulfilled.

The decision to omit model testing for smaller turbines should be based on a rationale similar to the example presented earlier in this section.

Competitive Testing

The competitive testing of models seeks to achieve the maximum performance gains possible for the owner. Competitive testing involves model testing being conducted by more than one manufacturer (numbers can range from 2 to 4 manufacturers) at the owner's expense with the best performing model being selected to be scaled up to complete the turbine upgrade. This process is usually only used for larger multiple unit projects where the economics of the situation allow as for the example below, but tenths of a percent are important. Also, the testing of each manufacturer's model is usually conducted at an independent laboratory to ensure all models are compared exactly and that test conditions are identical for all models. The cost of construction and testing of two models and conducting the tests at a third-party laboratory are incremental to the overall cost of competitive model testing.

Example
The Kaplan plant consists of 8 x 250 MW units operating 6,500 hours each per year on average. Gross revenues from the plant per year (at 3 cents/kWh) would be:

	250,000 kW x 8 units x 6,500 hours/unit x $0.03/kWh	=	$390M
∴	A 0.1% increase in revenue per year	=	$390 K

At an 8% discount rate over 20 years the present value of the increase in revenue of 0.1% is $3.9M.

If two competing models were used modeling costs would approach $1.3M - $1.8M.

From a schedule perspective, the competitive model test will likely add several months to the overall runner procurement time.

Independent Testing

Independent testing by a third-party laboratory is a common occurrence (far more so than competitive testing) which seeks independent verification of the manufacturer's own test results. This process has the advantages of:

- Providing independent verification of the manufacturer's claimed results, and
- keeping the testing process on schedule by specifying the date the model is required in the independent laboratory.

The cost of conducting independent testing is incremental to the overall modeling cost.

If independent testing is to be used the specification should ensure that the manufacturer's model will be compatible with the laboratory's equipment and that the manufacturer is aware of how its model will be tested and its performance assessed.

Semi-homologous Model Tests

To reduce the cost and schedule duration related to model testing, semi-homologous model tests are sometimes proposed. The model for the new runner is homologous to the prototype; however other turbine components may be from previous models. While the other components may be similar in shape to the design being tested, they are not strictly homologous. The concept may be attractive, where the added cost of fully homologous tests cannot be justified (e.g. due to relatively small unit capacity). This type of testing should be carefully evaluated, as small changes in geometry of the non-rotating components can affect performance. While such a test can increase confidence that the new runner design will perform satisfactorily, the estimate of prototype efficiency will be less accurate than with a fully homologous test.

For low head, high specific speed turbines, it is important that at least the draft tube be homologous to the prototype, because of the relatively high draft tube losses and necessity of matching the runner design to the draft tube.

Model Tests with the Existing Runner

As mentioned in Section 6.3.1, some plant owners, in addition to conducting model tests for the new runner design, also have a model of the existing runner constructed and tested. Such tests allow the comparative performance of the new and old designs to be established before proceeding with manufacture of the new runner(s). This can be most beneficial where no increase in turbine flow is contemplated and runner upgrade is for efficiency increase only. Small differences in efficiency can have a significant impact on the overall economics of runner upgrade.

The geometric shape of the existing runner is usually established by site measurements, using laser techniques or with a robotic arm specially designed for runner blade measurements.

Theoretical Modeling

Theoretical modeling, in the form of computational fluid dynamics (CFD), has improved greatly through the 1980's and 1990's thanks chiefly to the advances in available computing power and the development of new and more sophisticated computer codes.

CFD flow simulation modeling is used to investigate flow conditions in existing water passages of hydraulic machines. CFD modeling is also used to design new or modified water passages with improved flow characteristics.

Efficiency and other performance of hydraulic machines can be predicted on the basis of CFD flow simulation. CFD flow simulation can be performed in lieu of, or in conjunction with, physical model testing, depending on the project economics and the required level of accuracy of the performance characteristics of the hydraulic machine.

CFD modeling is used to optimize local components of the water passages (runner, wicket gates, spiral case, draft tube) and the entire water passages of the turbine in order to improve flow conditions and to achieve higher efficiencies over a wider operating regime.

CFD modeling has progressed to a point where flow in the water passages of a complete turbine, from the inlet of the spiral casing to the draft tube outlet, has been successfully modeled. Previously, flow simulations considered the stationary and rotating elements of a turbine separately. Error could then be introduced into the calculations due to the uncertainty in boundary condition of each interface between stationary and rotating elements. By coupling the stationary and rotating elements in one calculation domain it is now possible to improve the accuracy of CFD flow simulations for various operating regimes and, on this basis, to generate a complete turbine hill chart without model testing.

There is a degree of inaccuracy, however, in the exact prediction of efficiency which is attributable to the level of grid refinement and the choice of turbulence model. With present day computer techniques, the uncertainty in calculated efficiency is in the order of 0.3 to 0.5% for the optimum areas of the turbine hill chart and may be as high as 2% for off-design regimes. Therefore it is prudent to use CFD modeling in association with physical model testing, particularly in larger units (>100 MW) where the economics of small improvements in efficiency can be quite attractive.

CFD modeling is still useful in reducing the cost of the design process, even where physical modeling is required, by being used to optimize the design of the model prior to its construction and to reduce model manufacturing and testing time. As a minimum, CFD modeling of the runner is now a standard design tool of established turbine manufacturers.

8.3 Environmental Management Considerations

Environmental issues covered in Section 4 centered on the possible environmental impacts of hydro mechanical life extension and modernization projects. At the implementation stage of the process, the focus turns towards licensing approvals, the schedule to achieve them, and management of environmental matters on site during construction. In addition, the measurement of environmental improvements from the project is a necessary follow-up task. This subject is dealt with extensively in Volume 1, Section 6.

8.3.1 Licensing, Approvals and Schedules

Accurate estimates of improvement in environmental performance are a requirement in the relicensing process. The relicensing process may also require the owner to demonstrate that all available environmental upgrades have been considered and explain why some upgrade options are not being implemented. This process can be time consuming and allowance needs to be made in the implementation schedule to accommodate this.

8.3.2. Environmental Management Plans (EMP)

In order to ensure sound environmental management and to demonstrate due diligence to regulatory authorities and the public, an environmental management plan is required for most projects, from painting projects to equipment replacements and operational changes.

The purpose of an EMP is to ensure that the potential environmental impacts of a proposed activity (which does not require a legislated environmental impact assessment) are evaluated, and eliminated, mitigated or compensated for appropriately, and that these considerations are communicated appropriately in a responsible manner. EMP's also ensure that all required permits, authorizations and approvals are obtained and documented for due diligence purposes.

Like other environmental assessment tools, EMP's consider a proposed activity in the context of the existing environment in order to identify potential impacts and mitigation measures, provide an appropriate level of environmental protection, and ensure compliance with appropriate legislation and guidelines.

The content of an EMP depends upon the scope of the proposed undertaking. Depending upon the complexity of a proposed activity, and the environmental sensitivity, an EMP can be:

- instructions presented in a pre-job meeting
- a memo or letter
- clauses in tenders and contracts
- a stand-alone document
- all of the above

An EMP is also a valuable communication tool for the transmission of information in-house and to other stakeholders.

A reference collection of all existing EMP's, permit and authorization information and other useful material should be collated for easy reference on future projects.

An EMP will usually include the following sections:

1.0 Introduction
2.0 Project/Activity Description
3.0 Environmental Setting/Valued Ecosystem Components
4.0 Regulatory Requirements
5.0 Potential Environmental Impacts
6.0 Mitigation/Compensation
7.0 Literature Cited

Appendices:

Appendix 1 Project - Specific Environmental Protection Plan
Appendix 2 Environment Compliance Monitoring

Appendix 3 Regulatory Permits and Authorizations
Appendix 4 Emergency Contact List
Appendix 5 Material Safety Data Sheets (MSDS) Forms
Appendix 6 Test Results (analyses of paint, etc.)
Appendix 7 Spill Prevention and Response Measures
Appendix 8 Environmental Incident Reporting Procedures
Appendix 9 Suppliers (sorbents, etc.)
Appendix 10 Monitoring Forms

A very important part of any EMP is the monitoring requirements for the project. Environmental monitoring requirements should be well laid out and included as clauses in any external contracts for the work.

8.3.3 Construction Phase

Environmental management during the construction phase involves the consideration of the following aspects:

- Interference with the existing environmental management systems (such as drainage systems) in the plant.
- Losses to the environment due to mishaps during construction.

Existing Environmental Systems

When part of a plant is out of operation due to a construction project, the security of the environmental systems in the in-service portion of the plant may be reduced. For example, work on the station drainage system may limit the plant's capability of containing an oil spill occurring in the "in service" portion of the plant. Close coordination is required during the construction phase to avoid this type of situation. Daily coordination meetings between those involved in the construction project and those involved in plant operations can minimize the risks.

Losses to the Environment

The most common environmental risk with construction work is that of direct loss of construction materials and effluent to the environment (e.g. oil spill from a governor pressure unit or lube oil system during modifications). The mitigation of these risks lies with the contractor and the construction management team. The responsibilities and penalties associated with working to the required environmental regulations must be clearly defined for all parties at the start of the project. Daily coordination meetings, which include a discussion on activities that are potentially harmful to the environment, can be used as a risk mitigating activity.

8.4 Project Definition and Implementation Planning

To date, the life extension and modernization process has moved through its investigation and decision making phases. Once the decision is made to proceed with a particular project a new phase of the process is commenced - implementation.

Implementation consists of defining the project to be commenced and conducting and completing the defined project. Activities include:

- Project management
- Engineering
- Procurement
- Construction
- Construction Management
- Testing and Commissioning
- Documentation

Volume 1, Section 8 covers the project definition and implementation portion of the process in detail. It is recognized that each user will normally have procedures in place for these activities. Accordingly, the information presented is general in nature and intended to prompt some consideration of alternatives that may not currently be utilized by the user.

Who carries out the project activities will depend on the resources available and the contracting philosophy of the owner. All project activities may be undertaken by the owner's own engineering, maintenance and construction staff or all, or part , of the work may be contracted out.

8.5 Procurement Options

Procurement options are covered extensively in Volume 1 of these Guidelines. The options available to the user usually depend on the procurement philosophy of the owner. Each new project, however, provides an opportunity for the owner to revisit the options available to it to complete the project.

8.5.1 Traditional Approach

Broadly, there are three traditional types of contracts available for the completion of hydromechanical works as shown in the box below: They are divided on the basis of risk allocation.

Cost Reimbursement Contract (Cost Plus)

In this type of contract the owner pays the contractor for the actual cost of the work plus an additional amount representing the agreed profit.

The owner assumes most of the risk in this type of contract. Moreover the owner usually must survey the quality and quantity of work very closely to ensure that the work is sufficient, of acceptable quality, and performed expeditiously.

This type of contract is seldom used now.

Fixed Price Contract

In this type of contract the contractor agrees to do the required work for a fixed price.

The contractor assumes most of the risk in this type of contract.

This type of contract is popular for electrical and mechanical works where the quantities of work can be estimated accurately. It is also popular where the owner prefers to avoid the uncertainty of the contract cost.

Note, however, that despite the fixed price, there are a number of situations where the contractor may be entitled to extra payments. As with the re-measurement contract the fixed price contract may include provisional sums.

Turn Key Contract

In this type of contract the contractor agrees to design, procure, manage and implement the work for a fixed price. The contractor assumes most of this risk.

The contractor agrees to undertake the work and deliver the completed project to meet performance specifications. These are set by the owner as performance criteria to be met. The means by which the contractor undertakes the work is generally at their discretion, with payment based on satisfying the performance criteria. However, this increase can often be offset by innovative construction methods and competition in the bidding process. On the owner's side, engineering and management costs are sharply reduced. A prime consideration in the setting of performance criteria relates to long-term maintainability, quality and durability.

The types of contract above are general philosophies of approaching contracted work. The opportunity to provide some incentive for the contractor to provide performance above that specified as a minimum is available in the form of incentives. Incentives could take the form of:

- Bonus payments for performance improvement beyond the minimum specified. These can be made on a sliding scale.
- Bonus payments for early completion of the works.

- Using an "open book" methodology with an upper limit on cost of the project and a sharing of the cost saving by an agreed formula.
- Bonus payments are formulated in a manner such that there is no possibility of the payment costing more than its is worth.

8.5.2 Partnering

"Partnering" arrangements between owners and contractors are becoming a common method for the procurement and installation of equipment or for the design and management of projects.[1] Partnering involves the owner and contractor working together in a more open and cooperative atmosphere than that which traditionally exists when conventional "arms length" contracting is used. The process seeks to solve problems rather than protecting against litigation and is helpful in managing situations where hidden risks may exist.

8.5.3 Leasing

An alternative procurement approach for life extension and modernization projects involves leasing equipment.[2] The lease arrangement is much the same as for any commercial equipment lease except that ownership of the equipment reverts to the owner at the end of the lease period.

8.5.4 Performance Contracting

Another approach being developed is centered around improvements to the plant being financed and implemented by a third party in a form of performance contracting. The measured benefits of the improvement are paid to the third party initially to recoup its investment. To enable the transfer of the benefit of the installed improvement, the owner of the plant can have an equity interest in the third party which increases over time and gradually phases out the interest of the proponent that financed and installed the improvement. Depending upon the type of improvement the contract period may be anywhere from 5 to 20 years. Refer to Figure 8-3.

[1] *Hydropower Technology Round-Up Report; Part 1: Using Environmental Solutions to Lubrication; Part 2: Rehabilitating and Upgrading Hydro Plants,* EPRI, Palo Alto, CA, 1998.

[2] *Hydropower Technology Round-Up Report; Part 1: Using Environmental Solutions to Lubrication; Part 2: Rehabilitating and Upgrading Hydro Plants,* EPRI, Palo Alto, CA, 1998.

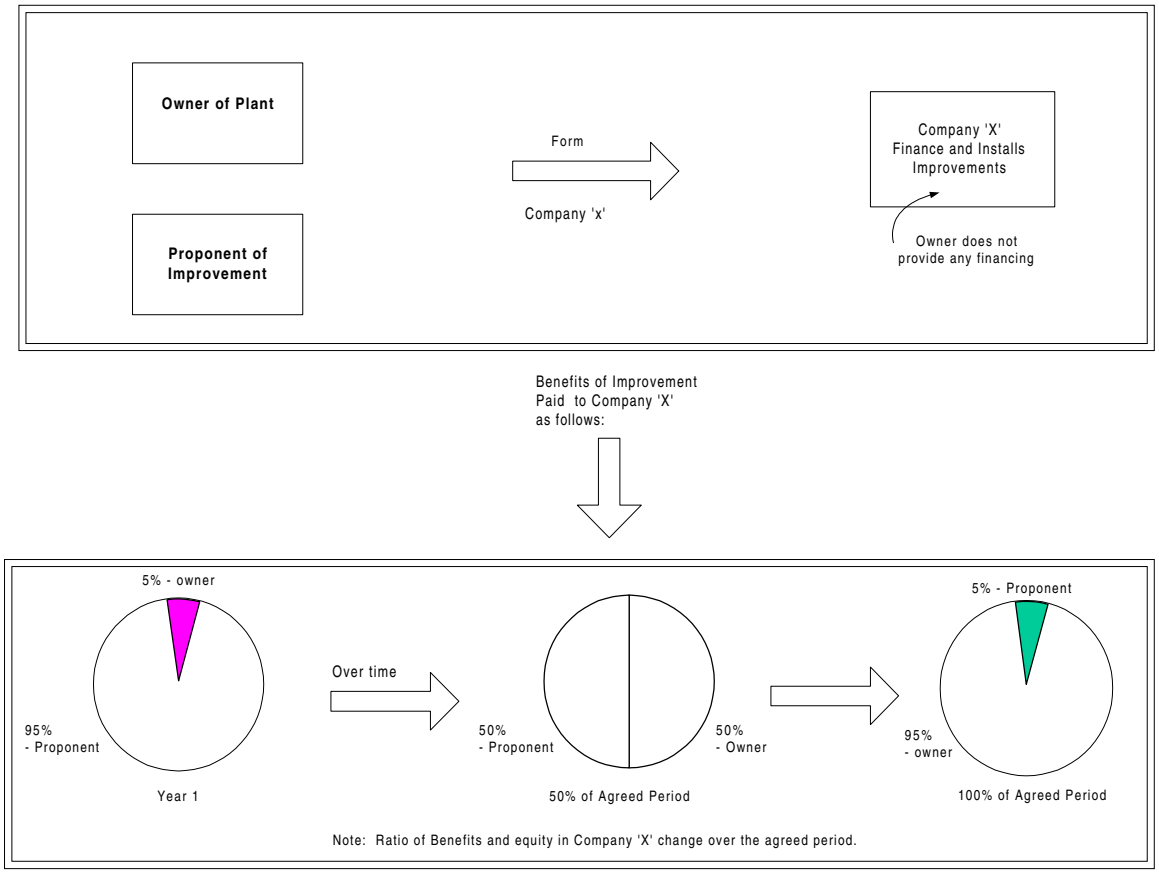
Owner of Plant
Proponent of Improvement
Form
Company 'x'
Company 'X' Finance and Installs Improvements
Owner does not provide any financing
Benefits of Improvement Paid to Company 'X' as follows:
5% - owner
95% - Proponent
Year 1
Over time
50% - Proponent
50% - Owner
50% of Agreed Period
5% - Proponent
95% - owner
100% of Agreed Period
Note: Ratio of Benefits and equity in Company 'X' change over the agreed period.

Figure 8-3
Example of Performance Contracting of Improvements

The advantage of this system to the plant owner is that the owner is not required to finance the improvement. The risk of the project is also laid with the improvement proponent as, if the benefits are not as good as expected, the owner has not incurred any cost. Even if the benefit is only 50% of that expected the owner has still achieved an improvement at no cost which it will eventually own. The proponent, however, will suffer a loss due to the improvement not being as successful as expected.

There are advantages to forming a third party company to conduct the improvement and allocating a portion of the company equity to the owner. The measurement of the benefit obtained can be clearly defined and a distinct payment for the benefit can be made. Giving the owner an initial small equity position also focuses the owner on accurately measuring the benefit. Also, at the end of the agreement, these can be a clear handover and exit of the improvement proponent.

8.6 Considerations for Technical Specifications

Specifications, along with the contracts they are associated with, are the means of transferring risk from owner to contractor. Therefore, it is important to ensure that the specification is designed not only to correctly transfer risk but also to minimize the risk payment that the contractor will seek from the owner. The more unknowns built into the specification, the more risk cost the contractor will build into its price.

This section is designed to provide assistance, at an overview level, to the user when preparing specifications. More detailed procurement guides for new runners, model testing and replacement governors are included in Appendix B. Most owners will have a procurement policy with standard documentation in place. The information given here and in Appendix B does not seek to replace the owner's standard documentation; rather to augment it.

These life extension and modernization guidelines do not seek to be maintenance guidelines. In any major works, however, it is only prudent to incorporate as much work as possible with any modernization work such as a runner replacement. Therefore, reference will be made to turbine refurbishment work in this section.

8.6.1 General

This section provides general guidelines to assist the user in contracting for turbine refurbishment work. It is not possible to adequately describe the turbine condition to allow contractors to prepare fixed price bids for turbine overhauls without the contractor incorporating a large risk premium. Prior to bidding, contractors may be requested to inspect the turbine, but these inspections will only reveal superficial defects and can give a rough indication of the duration and cost of the refurbishment.

Therefore, the repair of defects found during the refurbishment will require that some work be billed according to actual expenditures or on a unit price basis.

8.6.2 Request for Qualifications and Proposals

Details of publications which list turbine manufacturers and those which also have turbine overhaul experience are provided in Appendix C. Owners may wish to add local machine shops that also have overhaul experience. The first step is to select the potential bidders and prepare a Request for Qualifications and Proposals which is sent to each of the selected bidders.

The Request for Qualifications and Proposals should include the following information:

- All commercial terms (contractual obligations)
- All technical specifications for the work.
- All available turbine data.
- Drawings of all turbine components subject to refurbishment. The drawings should show the actual turbine design including any modifications that have been made to the turbine, the dates of the modifications, and the manufacturer.
- Report of most recent refurbishment work.
- Report of most recent maintenance work.
- List of all known deficiencies.
- Date of pre-bid inspection.
- Overhaul schedule.
- Support services provided by the owner.
- Bid date.

Inspection

A site inspection should be conducted prior to the submission of bids to allow contractors to identify general site conditions including access (or lack thereof). The site inspection may, or may not, include an internal turbine inspection. As discussed in Section 8.6.1, an internal inspection of the turbine may not assist contractors greatly in formulating their bids.

During the site inspection the owner should provide a knowledgeable contact person on site to answer questions and clarify the scope of the refurbishment work. It is important that there is only a single source of information from the owner to ensure that all parties receive the same advice so that the bids received are all based on the same information.

Bid

The bid should be divided into two parts:

- Standard overhaul lump sum cost.

- Unit quantity cost (including salaries and expenses) for unexpected repair and improvement work. In some cases this could be arranged as fixed price for particular works if they arise. Good examples are rebabbiting of turbine guide bearings or supply and installation of new wearing rings. Also, the costs could be fixed hourly rates for labour with an invoice plus a fixed percentage handling fee for materials.

The standard scope of refurbishment work includes:

- Disassembly and cleaning of turbine components.
- Inspection and identification of extra scope work.
- Standard repairs.
- Standard replacements.
- Painting of components.
- If applicable supply of new runner (along with repair of wear rings).
- Turbine reassembly.
- Commissioning.
- Commissioning tests.

Bid Evaluation, Bid Negotiations

The bids received will be evaluated by the owner's personnel or an outside engineer. All competitive bids will be adjusted to the same technical level by evaluation, combined if necessary with negotiations to enable meaningful price comparison. The contract for the refurbishment work is usually signed with the lowest bidder (this does not just include price) , unless unusual circumstances require the selection of another bidder.

Contract

The contract consists of the bid proposal and any agreements made during the contract negotiations. The overhaul contract should be co-ordinated with the runner design and replacement contract (if these are separate contracts).

Extra Scope Work

The inspection of equipment performed after disassembling the turbine components might reveal unexpected repair work, potential for improvements, and the need for spare parts. Generally, this additional work is authorized by the owner following negotiations and agreement of the additional scope and costs for this work.

8.7 Innovative Methods of Construction

Innovative methods of construction usually develop from an unusual problem that must be solved in the planning stages of a project. Hydropower magazines and journals often present case studies of interesting construction projects which are good sources for keeping abreast of new construction techniques that reduce costs and time. The following are some examples taken directly from published case studies that highlight some interesting approaches to construction.

1. Use of "in-house crews" for rehabilitation and upgrade projects.[3]

Sometimes, because contractors are unfamiliar with the equipment (and must include contingency in their price) combined with the cost of contract specification preparation, administration and inspection, the use of company personnel to form construction crews can save money. The best qualified and experienced personnel available are removed from their normal positions and temporarily replaced by less experienced personnel who are upgraded to these higher positions for the duration of the project. This is an excellent opportunity to develop in house skills for overhaul work. For the first few projects, the use of an external "Special Construction Crew" to provide specialty expertise and assistance is a good way of reducing risk due to inexperience. Videotapes of the first overhaul can be useful training tools on successive unit overhauls.

2. Overhaul/rewind of the generator at the same time as the turbine overhaul.[4]

Although scheduling the turbine and generator overhaul can often be economical, sometimes this is not true. Two separate crews competing for floor space, store parts, and crane use can extend the outage time. It may be economical in some cases for turbine and generator overhauls to be scheduled in succession or with only a partial overlap in timing.

3. More cost-effective way of installing unit throat rings with replaceable facing rings[5]

At the Northern States Power-Wisconsin (NSPW) Chippewa Falls hydro plant, instead of installing the four facing rings per unit using 240 bolts as anti-rotation devices, three of the four ring segments were welded together, then shrunk by cooling to fit in place. This allowed a good pressure fit and reduced the number of anti-rotation bolts needed in the fourth segment to 18. Reducing the bolting made drilling and counterboring the facing ring and drilling and tapping the backing rings unnecessary. The amount of welding needed to weld bolt heads into the facing rings was also reduced.

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[3] Olson, C., Holmberg, M., Kries J. and Lancor K., *"Renovating Chippewa Falls Hydro, Innovative Planning, Management"* in Hydro Review, August 1996.

[4] Miller, T., *"Lessons Learned from Turbine Rehabilitation by Seattle City Light"*, in International Journal of Hydropower Dams, Volume 2, No. 4.

[5] Olson, C., Holmberg, M., Kries J. and Lancor K., *"Renovating Chippewa Falls Hydro, Innovative Planning, Management"* in Hydro Review, August 1996.

4. Reduction in equipment costs and unit outage time for runner replacement.[6]

At Ontario Power Generation's (OPG formerly Ontario Hydro) R.H. Saunders hydro plant, large savings in equipment costs and in unit outage time were realized by using the existing turbine runner hubs. OPG purchased one new hub for use in the first upgraded unit. The new hub and new blades were fabricated while the unit remained in operation using the old runner. When completed, the new runner was swapped for the old. The old hub from the first unit became the hub for the second unit and so on through all the units. OPG will have one used hub left over at the end of the runner replacement.

OPG also decided to have the new blades bolted to each hub, rather than welded. This approach was adopted not only because it was less expensive, but also to provide flexibility for the future in the event that the angle of the blades needs to be altered.

5. Uprating of Cranes

A not uncommon large expense associated with runner replacement is the requirement to upgrade the powerhouse cranes. If the rotor was constructed in situ, the crane may not have the rated capacity to lift the complete rotor. A cost-saving measure may be to limit the uprating of crane capacity to the portion of the crane required for removal/installation of the heaviest component (usually the rotor). Limiting crane travel at a certain load may reduce uprating requirements on both the crane rails and bridge and the supporting powerhouse structure.

[6] Kee, D.C., Liscio, L.L., Ho, M.S., Eastman, K.T., *"Rehabilitating R.H. Saunders: Enhancing Value"*, in Hydro Review, December 1998.

A
LITERATURE REVIEW

Volume 2 Annotated bibliography of literature on Hydromechanical Components

V 2.1

TITLE	**21st century advanced hydropower turbine design**
AUTHOR	Brookshier, P., Flynn, J.& Loose, R. **COUNTRY** USA
PUBLICATION	United States. Department of Energy. (1995). 21st century advanced hydropower turbine design. Report # INEL-95/00357DOE, Washington, DC.
DATE	1995
KEY FOCUS	Turbine design New technology
SUMMARY	This paper describes the DOE Advanced Hydropower Turbine System Program for which the DOE, recognizing the need for turbines designed with environmental impact in mind, called for proposals for designs which sought innovative solutions and balanced environmental, technical and economic considerations.

V 2.2

TITLE	**Abrasion research and prevention**
AUTHOR	Krause, M. & Grein, H. **COUNTRY** Switzerland
PUBLICATION	*International Journal on Hydropower & Dams. Vol. 3, No. 4. p. 17-20.*
DATE	1996
KEY FOCUS	Abrasion Simulation model testing Turbines
SUMMARY	Combating abrasion is a multidisciplinary engineering task. Although abrasion rates can be predicted reasonably accurately on the basis of research findings and empirical data, this is not sufficient. State-of-the-art research is now well on the way to preventing abrasion altogether. The authors, affiliated with Sulzer Hydro, describe a simulation model of abrasion mechanism.

V 2.3

TITLE	**Better science supports fish-friendly turbine designs**
AUTHOR	Cada, Glenn **COUNTRY** USA
PUBLICATION	*Hydro Review, Vol. XVII, No. 6, p. 52 - 61.*
DATE	November 1998
KEY FOCUS	Fish safety New technology Turbine design
SUMMARY	A peer-reviewed paper which presents a different perspective on fish safety. The author argues that instrumentation and CFD modelling may provide considerable information on potential injury mechanisms within a turbine, but that biological knowledge is also required to define a safety zone which guarantees that injury mechanisms are at acceptable levels for survival. He presents a detailed summary of a literature review on the mechanisms of fish injury and mortality associated with turbine passage as studied under laboratory conditions. The US DOE is using the data to evaluate the results of conceptual turbine designs. The paper stresses the need for more research into indirect mortality if turbine design changes are to be optimized.

V 2.4

TITLE	**Case study for the upgrade and rehabilitation of a pumped storage installation at Muddy Run Powerhouse**
AUTHOR	Kepler, James & Jenkins, Thomas **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol. 1. ASCE, New York, NY. p. 1591-1599.*
DATE	1997
KEY FOCUS	Runners Wicket gates
SUMMARY	Eight turbines are involved in a major upgrade at PECo Energy's Muddy Run Storage Powerhouse, Pennsylvania. The rationale for the project and the design of components are discussed with charts and illustrations. Authors affiliated with Voith Hydro and PECo Energy.

V 2.5

TITLE	**CFD-driven rehabilitation of hydraulic power plants**
AUTHOR:	Sebestyen, Andreas, Sallaberger, Manfred & Keck Helmut **COUNTRY** Switzerland
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol. 3 ASCE, New York, NY. p. 1719-1728.*
DATE	1997
KEY FOCUS	Computational Fluid Dynamics Turbines Rehabilitation
SUMMARY	The use of CFD methods in fast response computations used in relation to turbine modification. The fast procedure results in an estimation of the profit in terms of overall efficiencies due to optimization of the hydraulic performance of the stay-vane profiles.

V 2.6

TITLE	**Conceptual planning for rehabilitation of the Boundary hydroelectric project**
AUTHOR:	Hayes, S. & Kobayashi, Vickie **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. v 3 ASCE, New York, NY. p 1694-1703.*
DATE	1997
KEY FOCUS	Automation Project Planning
SUMMARY	After an initial focus on rehabilitating the 1051 MW Boundary Hydroelectric Project from a maintenance perspective, Seattle City Light expanded its scope to include opportunities to enhance or upgrade equipment, systems and facilities. This paper focuses on the conceptual planning process used, the tools developed to analyze and manipulate data on individual work items, costs, schedule, and labor resources, and the final concept plan as it is being implemented.

V 2.7

TITLE	**Considerations for a major overhaul/modernization**
AUTHOR	Spicher, Thomas; Crahan, Marcus **COUNTRY**
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol. 3 ASCE, New York, NY. p 1710-1718.*
DATE	1997
KEY FOCUS	Condition assessment Occupational health and safety
SUMMARY	Addresses the practical considerations of the overhaul, reassembly and installation of various components of an upgrade with an emphasis on procedures, occupational health and safety and environmental factors.

V 2.8

TITLE	**Controlling cavitation in the 1990's:contours, materials, monitors**
AUTHOR	Fulton, E. **COUNTRY** USA
PUBLICATION	*Hydro Review. Vol. XV, No. 6. p. 16-22.*
DATE	September 1996
KEY FOCUS	Cavitation New technology Runners
SUMMARY	This article deals with new materials and methods that have been developed to repair damage to turbines caused by cavitation. The materials and methods are not only aimed at repairing the existing runner damage, but also preventing future damage caused by cavitation. Several case studies involving units with problem runners are presented, along with the solutions that were employed in order to remedy the cavitation problems. The author is a contributing editor to Hydro Review.

V 2.9

TITLE	**The design of a fish-friendly turbine runner**
AUTHOR	Jansen, W., Faulkner, H., Griffith, H. **COUNTRY** USA
PUBLICATION	Canadian Electricity Association. (1998). Electricity '98: Competition, Change, Technology: Section 4.
DATE	1998
KEY FOCUS	Fish safety Runners Turbine designs
SUMMARY	The conceptual design of a new runner is presented. Its physical features and flow characteristics should provide safe fish passage with an overall turbine power efficiency of about 90%. The design has been developed by Northern and Alden Research Laboratory, MA, in conjunction with the U.S. Department of Energy and the Hydropower Research Foundation.

V 2.10

TITLE	**Design by numbers**
AUTHOR	**COUNTRY** Switzerland
PUBLICATION	*International Water Power and Dam Construction. Vol. 50, No. 3. p. 20-22.*
DATE	March 1998
KEY FOCUS	Computational Fluid Dynamics Turbine design Francis Turbines
SUMMARY	The use of a 3D Navier Stokes code for a complete Francis turbine has rendered the numerical test rig a reality. Amply illustrated.

V 2.11

TITLE	**Designer turbines**
AUTHOR	**COUNTRY** USA
PUBLICATION	*International Water Power and Dam Construction. Vol. 49. No. 12. p. 16*
DATE	December 1997
KEY FOCUS	Turbine design New technology Software
SUMMARY	Hydro Info Systems, (HIS), has launched version two of Turbnpro™, a package designed to specify turbine size and type using specific site data entered by the user. Includes a library of 30 plus CAD compatible drawings. Presently covers Francis and Propeller type turbines, but an add-on program covering Pelton units is currently under development.

V 2.12

TITLE	**Developments in hydrogenerator thrust bearings**
AUTHOR	Knox, R.T. **COUNTRY** UK
PUBLICATION	*International Journal on Hydropower & Dams. Vol. 6, No. 3, P.16-17.*
DATE	1999
KEY FOCUS	New technology
SUMMARY	An report on further developments in PTFE bearings. With low frictional properties and chemical inertness, these bearings can be operated in demanding stop/star regimes without the risks associated with whitemetal bearings. Following prototype tests, and early applications using pure PTFE with no fillers, an improved form using a 33% carbon/25 graphite fill has been trialed. The new bearings were installed in a machine which had previously suffered serious malfunction, resulting from the effect of deformed runners on the whitemetal bearings. The PTFE bearings demonstrated, in situ, their ability to address the problem. Author associated with Michell Bearings, Newcastle-upon Tyne, UK. See also PTFE bearings offer reliability at Dinorwig for the original report on these bearings, and the successful results of their installation at two sites.

V 2.13

TITLE	**Digital governors take control in Brazil**
AUTHOR	Holl, H. P. **COUNTRY** Brazil
PUBLICATION	*International Journal of Water Power and Dam Construction. Vol. 49, No. 12. p.18-21.*
DATE	December 1997
KEY FOCUS	Digital governors New technology Software
SUMMARY	At 3000 MW, Xingó in Brazil is the world's largest hydropower plant to be controlled by digital governors. Features and advantages of the system are presented, prior to a discussion of the interfaces required, and the importance of software experts in the decision-making team. Author affiliated with Voith Hydro, São Paulo, Brazil.

V 2.14

TITLE	**Draft tube modification for a turbine upgrade**
AUTHOR	Faisst, K. & Coulson, S. **COUNTRY** Canada
PUBLICATION	*Uprating & Refurbishing Hydro Power Plants, 17 - 19 May, 1999. International Water Power and Dam Construction, Dartford, Kent. p. 285 - 294.*
DATE	1999
KEY FOCUS	Draft tubes Turbine upgrading
SUMMARY	In turbine upgrades embedded components such as draft tubes are usually ignored, unless they are damaged or the generating unit is being redeveloped. However, significant progress has been made in optimizing draft tubes as energy recovery devices, through the use of improved physical and numerical modelling techniques, and also a better understanding of the flow characteristics downstream of the turbine outlet. This technical paper details a recent Ontario Power Generation upgrade project which did include the modification of a 50 year old draft tube. The result has been an increase in peak efficiency by 55%, and by almost 2% at an output 10% beyond the peak point.

V 2.15

TITLE	**Dynamic testing, key upgrades lift hydropower to new heights**
AUTHOR	Giovando, CarolAnn **COUNTRY** USA
PUBLICATION	*Power. Vol. 142, No. 6, p. 82 - 86*
DATE	1998
KEY FOCUS	Automation Governors New technology
SUMMARY	The application of new technology to automate controls and monitor turbine/generator performance has paid dividends at three US hydropower stations. Forced outages have been dramatically reduced at Grand Coulee, WA; governor upgrades at Castaic CA, have led to increased competitiveness because the plant now qualifies for spinning reserve service; and advanced diagnostic techniques which revealed early vibration problems, have led the New York Power Authority to make MCM an integral part of plant automation.

V 2.16

TITLE	**Engineering guidelines for the evaluation of hydropower projects**
AUTHOR	FERC **COUNTRY** USA
PUBLICATION	*Engineering Guidelines for the Evaluation of Hydropower Projects. (1997). Federal Energy Regulatory Commission Office of Hydropower Licensing, Washington, DC. 100p.*
DATE	1997
KEY FOCUS	Evaluation criteria Guidelines
SUMMARY	Comprehensive guide to the recommended procedures and criteria for reviewing and evaluating hydropower plants in relation to FERC regulations for relicensing.

V 2.17

TITLE	**Enhancing turbine efficiency by replacing seal rings**
AUTHOR	Christenson, Dennis & Duncan, Bill Jr. **COUNTRY** USA
PUBLICATION	*Hydro Review. Vol XVII, No. 3. p. 62-68.*
DATE	April 1993
KEY FOCUS	Seal rings New technology Runners Turbine rehabilitation
SUMMARY	A technical article reporting on the findings of the US Bureau of Reclamation's 10 year program of experimentation with sealing ring replacement. The recommendation is for new materials which are gall resistant to each other and to wear, and designed featuring an integral seal surface on a turbine runner, instead of a separate rotating seal ring. Authors affiliated with USBR, Hungry Horse, Montana.

V 2.18

TITLE	**Evaluating and specifying pumped storage upgrades**
AUTHOR	Harty, F. Jr., Geuther, J., Jenkins, T. & Callahan, T. **COUNTRY** USA
PUBLICATION	*Waterpower ' 97. Proceedings of the International Conference on Hydropower. Vol. 3. ASCE, New York, NY. p 1683-1693.*
DATE	1997
KEY FOCUS	Pumped storage Evaluation criteria Project planning
SUMMARY	Increased station capacities in the order of 20% can be achieved by upgrading pumped storage facilities, but only if the upgrade program and equipment specifications take into account all opportunities and constraints. Using the examples of Yards Creek, Muddy Run and Taum Sauk, the paper explores some of the considerations that must be made in specifying an upgrade, and in guiding the manufacturer toward the design that will give the maximum return to the project.

V 2.19

TITLE	**Evaluation criteria for upgrading hydro powerplants**
AUTHOR	Gummer, B., Barr, D., Sims, G. **COUNTRY** General
PUBLICATION	*International Water Power & Dam Construction. Vol. 45, No. 12. p. 24-31.*
DATE	December 1993
KEY FOCUS	Evaluation criteria Condition assessment
SUMMARY	Criteria for an initial multi-disciplined survey to determine the need for a more detailed analysis is applied to economics, operation and maintenance, controls, dams, gates, the power house generating units and ancillary systems. Reasons for problems and alternatives for upgrading are suggested. See also V 1. General guidelines for upgrading hydro electric power schemes by the same authors.

V 2.20

TITLE	**Evolution of the governor-synchronizer**
AUTHOR	Clifton, Larry **COUNTRY** USA
PUBLICATION	*International Water Power & Dam Construction. Vol. 51, No. 8, p. 32-33*
DATE	1999
KEY FOCUS	Digital governors Governor-synchronizers New technology
SUMMARY	The merging of governing and synchronizing systems has enhanced performance levels of generating units. The design and implementation of modern digital governor-synchronizers is described. Author affiliated with Clifton & Associates.

V 2.21

TITLE	**Evolution of hydro turbine modernization**
AUTHOR	Gfeller, Werner **COUNTRY** Canada
PUBLICATION	Canadian Electricity Association.(1992). "Be part of the process: planning our electric future now". Proceedings of the CEA Conference, Montreal. CEA, Montreal. p. 602-619.
DATE	1992
KEY FOCUS	Modernization Turbine design
COMMENTS	An overview of the improvements in turbine design, and case studies of three modernization projects. Author affiliated with Turbine Engineering division of GE Canada.

V 2.22

TITLE	**Exotic alloys for cavitation resistance: passing the tests**
AUTHOR	Kumar, Ashok **COUNTRY** USA
PUBLICATION	*Hydro Review. Vol. XVII, No. 5. p. 16-21.*
DATE	September 1998
KEY FOCUS	Alloys Cavitation New technology Turbine rehabilitation
SUMMARY	Five cavitation resistant products are examined, and a report is given of USACE studies which quantifies the actual resistance of the alloys. Author affiliated with USACE Research Laboratories.

V 2.23

TITLE	**Extensive use of computational fluid dynamics in the upgrading of hydraulic turbines**
AUTHOR	Sabourin, M., Eremeef, R. & Henau, V. De **COUNTRY** Canada
PUBLICATION	*Electricity '95. Canadian Electrical Association. Vancouver. 1995.*
DATE	1995
KEY FOCUS	Computational fluid dynamics Runners Turbine rehabilitation
SUMMARY	The method used in the design of a rehabilitation project for either Kaplan and Francis turbines is presented. Authors affiliated with GEC Alsthom Canada and France.

V 2.24

TITLE	**Get wise to oil leaks**
AUTHOR	Inbar, Jacob **COUNTRY** USA
PUBLICATION	*International Water Power & Dam Construction, Vol. 51, No. 9, p. 38 - 39*
DATE	1999
KEY FOCUS	Environmental issues Oil leaks New technology Turbine sumps
SUMMARY	A new floating oil level sensor monitors oil layers in turbine sumps and is a safeguard against the discharge of contaminated water into rivers. The sensor has overcome the deficiencies of older capacitance and conductivity sensors with the use of energy absorption technology. A companion oil sheen detector is being used by utilities to monitor headgate hydraulic system fluid loss. Author affiliated with Ionics Agar Technologies, Watertown, MA.

V 2.25

TITLE	**High head Francis turbines - optimal refurbishing time**
AUTHOR	Nielsen, T.K., Romo, F. Hulaas, H and Lund, M. **COUNTRY** Norway
PUBLICATION	*UHRP '95. Conference on Uprating and Refurbishing Hydropower Plants, Nice, France, 9-11 October, 1995. International Wate Power and Dam Construction, Dartford, Kent, n.p.*
DATE	1995
KEY FOCUS	Environmental issues Francis turbines Turbine upgrading
SUMMARY	A report on the development of a computer program to simulate optimized refurbishment of Francis turbines according to both technical and economic considerations. The paper presents the principles of a correct maintenance strategy, based in and focusing on measured and expected developments in turbine efficiency. The methodology of the model is clearly set out, and explained using an example based on a real efficiency measurements performed over a number of years. Refurbishment strategies in relation to seasonal and daily variations in the energy market are discussed and illustrated. Authors affiliated with Kvaemer Energy a.s., Norway, and SINTEF, The Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology.

V 2.26

TITLE	**Hydraulic turbine design: will CFD replace model testing?**
AUTHOR	Henau, V., Sabourin, M., Labreque, Y. & Papillon, B. **COUNTRY** Canada
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol. 3. ASCE, New York, NY. p 1218-1227.*
DATE	September 1998
KEY FOCUS	Computational fluid dynamics Model testing Turbine rehabilitation Turbine upgrading
SUMMARY	The generating capacity of a plant may not justify the cost of model testing. This comprehensive article examines the potential of CFD to predict the performance of turbines being upgraded. Amply illustrated with tables. Authors affiliated with GEC Alsthom Energies, Quebec.

V 2.27

TITLE	**Hydro turbine profitability and cavitation erosion**
AUTHOR	Bourdon, P., Farhair, M., Mossoba, Y. & Lavigne, P. **COUNTRY** Canada
PUBLICATION	*Water '99. Hydro's Future: Technology, Markets and Policy. [CDROM]. ASCE, New York, N.Y.*
DATE	1999
KEY FOCUS	Cavitation Economic issues Turbine efficiency
SUMMARY	The profitable operation of hydraulic turbines is closely related to the optimal use of their efficiency curves. Expenses related to inspection or repairs related to cavitation erosion affect profitability. Hydro-Quebec has developed and validated a tool for coupling knowledge of erosion risk associated with operating conditions to the efficiency curves. Four case studies illustrate the application of the vibratory cavitation detection method to machines with existing cavitation problems, or to new or refurbished machines, to provide information minimizing maintenance costs and operating revenue losses. Both Kaplan and Francis turbines are included in the studies.

V 2.28

TITLE	**Hydro Wheels: a guide to maintaining & improving hydro units**
AUTHOR	Spicher, Thomas **COUNTRY** USA
PUBLICATION	Spicher, Thomas. (1997). Hydro Wheels: a guide to maintaining & improving hydro units. HCI, Kansas City, MO. 101pp.
DATE	1997
KEY FOCUS	Turbine testing Turbine upgrading
SUMMARY	An up-to-date handbook on turbine evaluation, repair and improvement.

V 2.29

TITLE	**IEEE recommended practice for preparation of equipment specifications for speed-governing of hydraulic turbines intended to drive electric generators**
AUTHOR	IEEE **COUNTRY** USA
PUBLICATION	Institute of Electrical and Electronic Engineers. IEEE recommended practice for preparation of equipment specifications for speed-governing of hydraulic turbines intended to drive electric generators.(125-1988).
DATE	1996
KEY FOCUS	Governors
SUMMARY	Includes the performance characteristics of a good governor system, adjustments and tests, information to be provided by the manufacturer to ensure that governor equipment will interface with other equipment and maintenance information.

V 2.30

TITLE	**Improved bearing system reduces outages**
AUTHOR	Pistner, Chuck **COUNTRY** USA
PUBLICATION	*Hydro Review, Vol XVI, No. 3. p 66.*
DATE	May 1997
KEY FOCUS	Bearings Turbine upgrading
SUMMARY	By modifying the turbine shoe bearings, bearing housings and support structures to eliminate excessive vibration, Tennessee Valley Authority has reduced the risk of forced outages and increased unit availability. Author affiliated with Voith Hydro.

V 2.31

TITLE	**Influence of surface finish on cavitation erosion**
AUTHOR	Rao, Avaral **COUNTRY** Canada
PUBLICATION	*Waterpower '99. Hydro's Future: Technology, Markets and Policy, [CDROM]. ASCE, New York, NY*
DATE	1999
KEY FOCUS	Cavitation Runners
SUMMARY	A technical paper which reports on a Powertech Labs Inc., B.C., study to determine whether surface treatment of a turbine runner affects cavitation behavior. It sought to provide a better understanding of the optimum surface finish for restored runners and the relationship between direction of grinding, water flow and cavitation damage. The influence of grinding, shot beening, sandblasting and light grinding on three steel runners was evaluated. Results from the limited data gathered indicate that the nature of the surface and the direction of grinding do affect the degree of erosion.

V 2.32

TITLE	**Lessons learned from turbine rehabilitation by Seattle City Light**
AUTHOR	Miller, T. R. **COUNTRY** USA
PUBLICATION	*International Journal on Hydropower & Dams. Vol. 2. No. 4. p. 27-34.*
DATE	July 1995
KEY FOCUS	Runners Turbine rehabilitation
SUMMARY	In a program to rehabilitate their 16 oldest hydraulic turbines Seattle City Light determined that replacing runners with new ones , rather than refurbishing, would lead to an increase of total unit capacity equivalent to a small hydro plant. The article details the work on each of the units.

V 2.33

TITLE	**Measuring turbine flows with an acoustic scintillation flow meter**
AUTHOR	Lemon, D., Almquist, C., Cartier, W., March, P. & Brice, T. **COUNTRY** USA
PUBLICATION	*Hydro Review. Vol. XVIII, No. 2, p. 32 - 39*
DATE	April 1999
KEY FOCUS	Flow measurement New technology
SUMMARY	The TVA compared two methods for measuring flow discharge from an upgraded 40-MW Francis turbine, a traditional current meter and the relatively new acoustic scintillation flow meter (ASFM). The ASFM has the advantage of less blockage of flow through the turbine, and less work in installation, calibration and maintenance. Plant downtime and resulting costs are minimized. This peer-reviewed technical article details the results of the study which showed that the ASFM compared favourably with the current meter, displaying the accuracy required to measure discharge under operational conditions. The TVA is continuing to evaluate the method in another series of performance tests.

V 2.34

TITLE	**Model testing for Beauharnois powerplant's refurbishment project**
AUTHOR:	Dumoulin, Ch, Mombelli, H., Avellan, F, Roy, M. & Brassard, A **COUNTRY** Canada
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol. 3 ASCE, New York, NY. p. 1666-1672.*
DATE	1997 **COUNTRY** Canada
KEY FOCUS	Model testing Runners Turbine rehabilitation
SUMMARY	When faced with the prospect of replacing 6 Francis runners and 10 propeller runners economically, Hydro-Quebec's approach was to use comparative model tests of existing and replacement turbines at a reduced scale using a new runner system model supplied by the manufacturer. The procedure is detailed.

V 2.35

TITLE	**Modernization and performance improvements of vertical Pelton turbines**
AUTHOR	Gass, Matthew **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol. 3, ASCE, New York, NY. p 2073-2082.*
DATE	1997
KEY FOCUS	Economic issues Modernization Pelton turbines Turbine upgrading
SUMMARY	Hetch Hetchy Water and Power, eastern California, is carrying out a major and economical program to modernize, upgrade and increase the performance of 7 of its high head six-jet Pelton turbines. A checklist of items for investigation is given, and case studies detail the modifications made to 3 plants, giving costs and efficiency gains. Author affiliated with Hetch Hetchy Water and Power.

V 2.36

TITLE	**Nantahala control upgrades provide cost savings**
AUTHOR	Neumeuller, Scott, Wright, Jerry **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol. 1. ASCE, New York, NY. p. 704-712.*
DATE	1997
KEY FOCUS	Synchronization Turbine upgrading
SUMMARY	The upgrade of two generating units, one vertical Francis , the other a single-needle Pelton, at the Queen's Creek and Nantahala powerhouses in North Carolina, has considerably reduced start-to-synchronized time, improved unit protection start, and reduced costs. Authors affiliated with Woodward Governor Company and Nantahala Power and Light.

V 2.37

TITLE	**New approach eases inspection of turbine hub**
AUTHOR	Brittain, Tom **COUNTRY** USA
PUBLICATION	*Hydro Review. Vol XVI, No. 3. p 64-65.*
DATE	May 1997
KEY FOCUS	Turbine inspection
SUMMARY	An innovative procedure for lowering the nose cone of a Kaplan turbine saved more than 5 months of unit downtime and about a million dollars. Author affiliated with Public Utility District No. 2, Grant County, WA.

V 2.38

TITLE	**New Francis units for the renovation of the Hemfurth I powerplant**
AUTHOR	Weigel, G **COUNTRY** Germany
PUBLICATION	*International Journal on Hydropower and Dams, Vol. 3, No. 3. p. 32-36.*
DATE	1996
KEY FOCUS	Automation Francis turbines
SUMMARY	Two new Francis turbines, with direct-coupled synchronous generators have replaced six generating units at the Hemfurth I hydroelectric power plant in Germany. The operation, monitoring and control of the plant is now fully automated. Energy production has significantly increased.

V 2.39

TITLE	**A new method for updating operating characteristics of a hydroturbine**
AUTHOR	Giles, James E. & Jones, R. Keith **COUNTRY** USA
PUBLICATION	*Hydro Review. Vol. XVII, No. 7, p. 34 - 39.*
DATE	1998
KEY FOCUS	Turbine efficiency Wicket gates
SUMMARY	The Tennessee Valley Authority is modernizing 92 of its 113 hydroelectric units. TVA engineers are updating the operating characteristics for the rehabilitated units to accurately describe the hydraulic operation of the turbine under all possible heads and gate settings. The authors have developed a new method of combining data from both field performance tests and scaled-up model tests to accurately estimate performance over a range of heads. A feature of the method is the recognition and exploitation of the uncertainties present in both types of tests to produce adjusted curves which lie within the uncertainty limits of the test points and reflect the geometry of the model. This addresses the problem of adapting a single-head field performance test to a whole range of unit operating characteristics. A peer-reviewed paper.

V 2.40

TITLE	**Ontario Hydro: Sir Adam Beck Pump Generating Station: Thrust bearing and runner servomotor rehabilitation**
AUTHOR	Barbour, J. & Garro, A **COUNTRY** Canada
PUBLICATION	Canadian Electricity Association. (1998). Electricity '98: Competition, Change, Technology: Section 4.
DATE	1998
KEY FOCUS	Bearings Deriaz turbines Runners Servomotors Thrust bearings
SUMMARY	The Sir Adam Beck Pump Generating Station has six 25 MW Deriaz turbines. The effect of the unusual arrangement and operation of the runner blades, and the lack of wicket gates in these units results in thrust bearings experiencing maximum load at start. Following recurring failures after an overhaul, an investigation revealed several possible causes. The range of actions and precautions taken during reassembly and following resumption of operation are detailed. The overhauling has been successful.

V 2.41

TITLE	**Pelton technology for new plants and modernization schemes**
AUTHOR	Keck, H, Scharer, C., Cuenod, R. & Cateni, A. **COUNTRY** Europe
PUBLICATION	*International Journal on Hydropower and Dams. Vol 4, No 2. p 104-108.*
DATE	1997
KEY FOCUS	New technology Pelton turbines
SUMMARY	Recent developments in the field of Pelton turbine technology, both for new projects, and uprating and refurbishment schemes, are discussed. Case studies are included to give some examples of trends in this field.

V 2.42

TITLE	**Prediction and improvement of off-design performance of large hydro power turbines**
AUTHOR	Hawley, Nick **COUNTRY** Canada
PUBLICATION	FED-Vol 136, Hydropower Fluid Machinery. ASME, 1992. p. 129-135.
DATE	1992
KEY FOCUS	Model testing Turbine testing
SUMMARY	A detailed technical paper to be used as a guide for an investigation into the performance of an existing unit. Particularly useful for engineers who have not carried out such an investigation before. Presents the methodology for efficiency testing at site, model testing, and analysis of improvement options. Illustrated with charts, tables and diagrams.

V 2.43

TITLE	**PTFE bearings offer reliability at Dinorwig**
AUTHOR	**COUNTRY** UK
PUBLICATION	*International Water Power and Dam Construction. Vol. 50, No. 8, p. 41.*
DATE	1998
KEY FOCUS	Bearings New technology
SUMMARY	Changes in the usage of plants since the privatization of the UK electricity supply industry have led to the design of a new bearing made of PTFE, which improves reliability and wear resistance under demanding stop/start conditions. The Tetraglide bearings have been installed in the Dinorwig and Ffestinog pumped storage plants which have up to 14 mode changes a day. They have three times the load capacity of white metal bearings, are tolerant of load and thermal transients, and eliminate the need for high pressure oil injection at startup. Power loss is reduced up to 30%, and circulating currents are eliminated. Although more expensive than traditional bearings, there are substantial cost savings associated with their special features. See also Development in hydrogenerator thrust bearings, for an update on further developments of these bearings.

V 2.44

TITLE	**Puget Power's hydro modernization project: a diversified approach**
AUTHOR	Haynes, M, Webber, D. & Yale, J. **COUNTRY** USA
PUBLICATION	*Waterpower '93. Proceedings of the International Conference on Hydropower. Vol. 3. ASCE, New York, NY. p. 1671-1680.*
DATE	1993
KEY FOCUS	Modernization Project planning
SUMMARY	The conceptual design process, specification development and proposed project modifications for the modernization of the 6 power plants in Washington's Puget Power's system.

V 2.45

TITLE	**Refurbishment and uprating of Tumut 1 and Tumut 2 power stations: a case study**
AUTHOR	Whitby, Roger **COUNTRY** Australia
PUBLICATION	*Uprating and Refurbishing Hydro Power Plants V Conference Proceedings. International Water Power and Dam Construction, Surrey, UK. n.p.*
DATE	1995
KEY FOCUS	Project planning Runners Turbine upgrading
SUMMARY	The predicted imminent failure of the stator windings prompted this AUD$50 million project. Studies also indicated that the generators could be uprated by 20% for little extra cost, and that efficiency and capacity gains could be achieved by upgrading the turbine runners. This extensive report details the technical aspects of the upgrading and how technical, contractual and management problems were overcome.

V 2.46

TITLE	**Rehabilitation of the high dam hydroelectric facility**
AUTHOR	Lavigne, J. Jr., Cote, W. & Nolan, P. **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol. 3. ASCE, New York, NY. p. 2037-2045.*
DATE	1997
KEY FOCUS	Automation Turbine evaluation Turbine rehabilitation
SUMMARY	Modification of existing turbines and conversion to an automated system proved the most cost effective solution to the upgrade of the Oswego power station. Capacity has improved from 5.5MW to 9.2 MW, and a 37% increase in energy is projected. Includes findings of the preliminary engineering analyses.

V 2.47

TITLE	**Rehabilitation of Unit #2 at Bennett's Bridge Hydro**
AUTHOR	Bernhardt, Paul A. **COUNTRY** USA
PUBLICATION	*Waterpower '93. Proceedings of the International Conference on Hydropower. Vol. 3. ASCE, New York, NY. p. 1607-1618.*
DATE	1993
KEY FOCUS	Economic issues Life extension Project planning Turbine rehabilitation
SUMMARY	The project history, economic analysis, index testing method and index test results of the rehabilitation of the #2 horizontal Francis (double discharge) turbine at Niagara Mohawk Power Corporation's Bennett's Bridge plant. A 32% increase in maximum power capacity and an expected life extension of 25 years of that unit led the company to proceed with the rehabilitation of the remaining 3 units. Good data analysis. Author affiliated with NMP, Syracuse, NY.

V 2.48

TITLE	**Residual life analysis of critical hydraulic machinery components**
AUTHOR	Angehrn, R. **COUNTRY** Switzerland
PUBLICATION	*Uprating and Refurbishing Hydro Power plants- IV. Conference Papers. (1993). International Water Power and Dam Construction, Surrey, UK. 572 p.*
DATE	1993
KEY FOCUS	Residual life analysis
SUMMARY	A Residual Life Analysis (RLA) evaluates the safety of components which should remain in an upgraded machine. Using an example, a detailed and technical discussion of the methods, procedures, targets and test results is given. Illustrated with technical drawings and graphs. Author affiliated with Sulzer-Escher Wyss, Zurich, CH.

V 2.49

TITLE	**Reviewing the approaches to hydro optimization**
AUTHOR	Sheldon, Lee **COUNTRY** USA
PUBLICATION	*Hydro Review, Vol. XVII, No. 3. p. 60-67.*
DATE	June 1998
KEY FOCUS	Optimization Software Turbine testing
SUMMARY	A review of single unit, powerhouse load and system optimization, and the techniques for achieving them. Methods of testing are discussed and a list of optimization software is provided. Author affiliated with Kleinscmidt Associates.

V 2.50

TITLE	**Runner upgrading: learning from Ontario Hydro's experience**
AUTHOR	Kee, D., Markovoch, M. & Munro, R.I **COUNTRY** Canada
PUBLICATION	*Hydro Review. Vol. XVI, No. 1. p. 10-16.*
DATE	February 1997
KEY FOCUS	Project planning Runners
SUMMARY	Lessons learned from more than 20 years' experience of replacing runners in 78 units now comprise an important part of Ontario Hydro's upgrade planning process.

V 2.51

TITLE	**Selecting alloys for optimum turbine life and efficiency**
AUTHOR	Medley, David **COUNTRY** USA
PUBLICATION	FED-Vol 136, Hydropower Fluid Machinery. ASME, 1992. Pp. 71-75.
DATE	1992
KEY FOCUS	Alloys Cavitation New technology
SUMMARY	In turbine design the importance of considering materials of construction is often overlooked. Selection of suitable alloys reduces wear and damage, prolongs efficiencies and reduces maintenance costs. This paper reviews research carried out into the development of alloys to address the problems of wear, galling, cavitation, erosion and corrosion. Includes an analysis of particular alloys in relation to their special characteristic and their application to these problems. Author affiliated with Wisconsin Centrifugal, Waukesha, WI.

V 2.52

TITLE	**Semi-Kaplan turbines for economic low head power generation**
AUTHOR	Maurer, E.A. **COUNTRY** Spain
PUBLICATION	*International Journal on Hydropower & Dams. Vol. 3 No. 6. p. 40-41.*
DATE	1996
KEY FOCUS	Kaplan turbines Economic aspects Turbine efficiency
SUMMARY	Despite a low head and widely varying flow rate the balance between economy and reliability has been achieved by installing two Semi-Kaplan units, compact Kaplan turbines which operate with fixed guidevanes and controllable runner blades. Author affiliated with Sulzer Hydro Ltd, Zurich.

V 2.53

TITLE	**Shaft vibration diagnosis in condition-based monitoring**
AUTHOR	Grosse, G. & Kopf, E. **COUNTRY** Germany
PUBLICATION	*International Journal on Hydropower & Dams. Vol. 3, No. 3.*
DATE	1996
KEY FOCUS	New technology Vibration diagnosis
SUMMARY	Vibration diagnosis has become a powerful tool for condition-based maintenance of hydraulic turbines. Accurate evaluation of the cause of vibrations depends on the precision of the calculation model, and the adequacy of the knowledge base. The integration of diagnostic tools into the automation and supervisory control and data acquisition (SCADA) system is necessary for easy access to information about the operating points.

V 2.54

TITLE	**Short payback period of turbine control and monitoring systems for low head powerstations**
AUTHOR	Huser, Ludwig; Meier, Christian **COUNTRY** Switzerland
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower. Vol 2. ASCE, New York, NY. p 1144-1153.*
DATE	1997
KEY FOCUS	Economic issues Optimization Turbine evaluation
SUMMARY	Describes the 4 phase method applied by Sulzer Hydro to optimize the low head Birsfelden Hydro Station on the River Rhine. For effective energy management, the knowledge of the actual turbine characteristics is essential. The optimization has led to efficiency improvement, annual energy gain and a short payback period.

V 2.55

TITLE	**The sliding gate method : a better way of turbine efficiency testing?**
AUTHOR	Almquist, C., March, P. & Franseen, H. **COUNTRY** USA
PUBLICATION	*Hydro Review, Vol XVI, No. 3. p. 44-53.*
DATE	May 1997
KEY FOCUS	Turbine efficiency Turbine testing
COMMENTS	Comprehensive article on this alternative testing method which offers the potential of enhancing test accuracy and reducing cost.

V 2.56

TITLE	**Software-based governor control helps manage power swings**
AUTHOR	Bauman, Terry & Stead, Donald **COUNTRY** USA
PUBLICATION	*Hydro Review. Vol. XIV, No.7. p.44-50.*
DATE	December 1995
KEY FOCUS	Control systems Governors New technology Pelton turbines Software
SUMMARY	State of the art digital electronics were used to address the problem of severe power swings to impulse (Pelton) turbines at the Bradley Lake Project, Homer, Alaska. The use of computer software rather than an analogue controller with expensive, labor-intensive hardware, enabled the problem to be solved in one week. The software can be replicated on impulse turbines with an even number of needle valves, or on units equipped with bearings capable of handling unequal loading on the turbine. Authors affiliated with Woodward Governor Company, Loveland, CO., and Homer Electric Association, AK.

V 2.57

TITLE	**State of the art in Pelton turbine design**
AUTHOR	Brekke, H. **COUNTRY** Norway
PUBLICATION	*International Journal on Hydropower & Dams. Vol. 1 No. 2. p.21-28.*
DATE	March 1994
KEY FOCUS	Pelton turbines New technology Turbine design
SUMMARY	Technical paper giving comprehensive overview of trends, objectives, recent achievements and limitations of Pelton turbines. Includes discussion of back pressure units and brief comparison of Pelton and Francis machines. Recommended reading. Author affiliated with The Norwegian Institute of Technology.

V 2.58

TITLE	**Synchronizing upgrade for hydroelectric plants**
AUTHOR	Harlow, James **COUNTRY** USA
PUBLICATION	*Waterpower '93. Proceedings of the International Conference on Hydropower. Vol. 3. ASCE, New York, NY. p. 1564-1573.*
DATE	1993
KEY FOCUS	Automation Control systems Turbine upgrading
SUMMARY	Upgrading of the automatic synchronizing system for the turbines of two plants to ensure that the synchronizing function is dependable when started remotely. The author reports excellent results. Detailed diagrams of the relay systems included. Author affiliated with Beckwith Electric Company

V 2.59

TITLE	**Testing environmentally safe "green" lubricants for wicket gates**
AUTHOR	Hanna, Leslie & Pugh, Cliff **COUNTRY** USA
PUBLICATION	*Hydro Review. Vol. XVIII, No. 1, p. 42 - 47.*
DATE	February 1999
KEY FOCUS	Environmental issues Lubricants Wicket gates
SUMMARY	A peer-reviewed report on research by the Bureau of Reclamation which aimed to identify possible replacement greases for use in wicket gate bushings. The test program compared the lubricating performance of five "environmentally safe" lubricants an done self-lubricating bushings, relative to the performance of a standard lithium-based grease with encouraging results. Significant conclusions were that ester-based lubricants performed significantly better than food grade greases and that the self-lubricating bushing provided 86% of the lubrication difference between the water-lubricated and lithium-based lubricant. Recommendations are made for the focus of future testing.

V 2.60

TITLE	**Turbine generator plant monitoring: towards integrated systems**
AUTHOR	McDonald, J., Moyes, A., & Georgin, E. **COUNTRY** UK
PUBLICATION	*ISAP 96. International Conference on Intelligent Systems Applications to Power Systems; Proceedings. (1996). IEEE, Piscataway, NJ. p. 151-155*
DATE	1996
KEY FOCUS	Turbine monitoring
SUMMARY	Research shows that it is feasible to use multiple sources of knowledge, representations and problem-solving techniques to provide advanced decision support for turbine generator plant operators. Two case studies are given.

V 2.61

TITLE	**Two approaches to turbine upgrades: planned and unplanned**
AUTHOR	Rittase, R.A. **COUNTRY** USA
PUBLICATION	*International Journal on Hydropower & Dams, Vol.2, No.4. p.58-64.*
DATE	July 1995
KEY FOCUS	Project planning Turbine upgrading
SUMMARY	When a major mechanical failure occurs the approach to the rehabilitation of a turbine is very different from a planned upgrade. Apart from deciding on repair action, steps must be taken to ensure that the failure will not be repeated. PECO Energy has had to deal with both types of rehabilitation in recent years at Conowingo and Muddy Run. A comparative study showed the advantages of planning for rehabilitation and outage. Efficiency charts and computer simulations illustrate the paper. Author affiliated with Voith Hydro, Inc., Pennsylvania, USA

IEC Standards

IEC 60041 (1991-11) Field acceptance tests to determine the hydraulic performance of hydraulic turbines, storage pumps and pump-turbines

IEC 60193 (1999-11) Hydraulic turbines, storage pumps and pump-turbines - Model acceptance tests

IEC 60308 (1970-01) International code for testing of speed governing systems for hydraulic turbines

IEC 60545 (1976-01) Guide for commissioning, operation and maintenance of hydraulic turbines

IEC 60609 (1978-01) Cavitation pitting evaluation in hydraulic turbines, storage pumps and pump-turbines

IEC 60609-2 (1997-11) Cavitation pitting evaluation in hydraulic turbines, storage pumps and pump-turbines - Part 2: Evaluation in Pelton turbines

IEC 60805 (1985-09) Guide for commissioning, operation and maintenance of storage pumps and of pump-turbines operating as pumps

IEC 60994 (1991-02) Guide for field measurement of vibrations and pulsations in hydraulic machines (turbines, storage pumps and pump-turbines)

IEC 61116 (1992-10) Electromechanical equipment guide for small hydroelectric installations

IEC 61362 (1998-03) Guide to specification of hydraulic turbine control systems

IEC 61364 TR (1999-07) Nomenclature for hydroelectric powerplant machinery

IEC 61366-1 TR3 (1998-03) Hydraulic turbines, storage pumps and pump-turbines - Tendering Documents - Part 1: General and annexes

IEC 61366-2 TR3 (1998-03) Hydraulic turbines, storage pumps and pump-turbines - Tendering Documents - Part 2: Guidelines for technical specifications for Francis turbines

IEC 61366-3 TR3 (1998-03) Hydraulic turbines, storage pumps and pump-turbines - Tendering documents - Part 3: Guidelines for technical specifications for Pelton turbines

IEC 61366-4 TR3 (1998-03) Hydraulic turbines, storage pumps and pump-turbines - Tendering Documents - Part 4: Guidelines for technical specifications for Kaplan and propeller turbines

IEC 61366-5 TR3 (1998-03) Hydraulic turbines, storage pumps and pump-turbines - Tendering Documents - Part 5: Guidelines for technical specifications for tubular turbines

IEC 61366-6 TR3 (1998-03) Hydraulic turbines, storage pumps and pump-turbines - Tendering Documents - Part 6: Guidelines for technical specifications for pump-turbines

IEC 61366-7 TR3 (1998-03) Hydraulic turbines, storage pumps and pump-turbines - Tendering Documents - Part 7: Guidelines for technical specifications for storage pumps

B
PROCUREMENT GUIDES

As set out in Section 8.5, the following are procurement guides for:

- replacing a turbine runner
- turbine model testing,
- replacing a governor.

Generally, these guides are intended to show the user the areas that require coverage in specifications of this type. These guides also supply some of the words which can be used directly in a specification if the user desires.

Specifications will vary according to turbine and governor type. The guides have taken this into account in some areas by the use of parenthesis giving the words to be used for each type of turbine or governor identified. In some areas this has not been possible due to the level of detail required for each type of turbine or governor. Where this has occurred, only general statements have been included to prompt the user to provide the detail necessary. Also, there are occasions where the user will have their own requirements for performance and test points and, as such, it is up to the user to provide the necessary information.

The turbine model testing guide is based on the Model Testing Specification included in Appendix D of the Electric Power Research Institute's Guide For Hydraulic Machinery Model Testing (EPRI AP-5876, Project 2602-1, Final Report June 1998). Competitive model testing is recommended for large multiunit plants having plant capacities greater than 100 MW.

1. Procurement Guide for a (Francis) (Kaplan) (Fixed Blade Propeller) Turbine Runner

1.1 General

The scope of work shall include the following:

- Supply and installation of a new runner(s) for the existing (Francis) (Kaplan) (Fixed blade propeller) turbine(s).
- All necessary modifications to the associated turbine components, such as the runner band and crown seals, head cover, discharge ring, runner to shaft flange, etc..

1.2 Existing Turbine(s)

The existing turbine(s) is (are) a vertical (horizontal) (Francis) (Kaplan) (fixed blade propeller) type turbine(s) with the wicket gate (turbine shaft) centerline at elevation ____ ft (m) msl.

The turbine generator and governor arrangement drawings showing the equipment layout and overall dimensions are attached to these specifications.

1.3 Operating Conditions

1.3.1 Operation Conditions for Turbine with New Runner

(a) Headwater Levels

maximum operating	_____ ft (m) msl
design	_____ ft (m) msl
minimum operating	_____ ft (m) msl

(b) Tailwater Level

The tailwater rating curve is shown in Attachment 1.

(c) Net Heads

maximum	_____ ft (m)
rated	_____ ft (m)
design	_____ ft (m)
minimum	_____ ft (m)

(d) Flow

maximum allowable flow through 1 turbine	_____ cfs (cms)

(e) Rated Speed _____ rpm

(f) Maximum allowable runaway speed _____ rpm

(g) Maximum allowable pressure rise at Turbine Inlet above maximum static pressure

	(following load rejection)	_____ psi (kPa)
(h)	Maximum Allowable Overspeed	
	(following load rejection)	_____ rpm

1.3.2 Parameters of Existing Generating Units

(a)	Generator Flywheel Effect	_____ lb-ft^2 (kgm^2)
(b)	Direction of Rotation when	
	viewed from (above) (the generator side)	Clockwise (Counterclockwise)
(c)	Governor Oil Pressure	
	maximum operating	_____ psi (kPa)
	minimum operating	_____ psi (kPa)
(d)	Existing Stationary Runner Seals	
	material	_____
	hardness	_____

1.4 General Requirements

The runner shall be designed to utilize to the maximum extent possible the maximum flow in Section 1.3.1(d) and shall be designed for the existing turbine dimensions with minimal modifications. The cost of all turbine modifications shall be included in the contract price. The runner shall be installed (from above through the generator stator), (from below), (from between turbine and generator, disassembling an intermediate shaft).

The maximum pressure rise and overspeed following load rejection under the most unfavourable conditions shall not exceed the values specified in Sections 1.3.1(g) and 1.3.1(h). The Contractor shall be responsible for all measurements of the existing turbine, and shall be responsible for conformity with available drawings, and fit of parts when installed. The Owner will not accept responsibility for errors.

The Contractor shall provide complete and detailed fabrication drawings, material specifications, test reports, and calculations as required for the safe operation and proper maintenance of the upgraded turbine.

1.5 Runner Design

(a) Francis Turbine

All runner surfaces in contact with water shall be machined and finished smooth by grinding and shall be free from irregularities such as hollows, cracks, projections, and porosity that may cause cavitation. After weld assembly, the runner shall be stress-relieved by heat treatment, unless the welding is done with austenitic stainless steel filler metal. Dimensional tolerances, profile tolerances, waviness, and surface roughness of all turbine parts which will be in contact with the water, shall be equal to or less than those parameters indicated by IEC Code, Publication No. 60193, Amendment No. 1, except for the surface roughness of the runner which shall not exceed the following values:

Surface	Surface Roughness Ra, Microinches
Trailing half of low-pressure side of runner blade, inlet and outlet edges of runner blade	125
Remaining runner surfaces	250

The runner crown and band shall be provided with stainless steel seals. To prevent galling, the rotating seals shall have a (Rockwell) (Brinell) hardness of at least __ (R)(50 BHN), a hardness higher than the adjacent stationary seals.

1. (Only for vertical axis machines.)

   The runner shall be designed to allow vertical movement to allow the disassembly from the generator coupling and disassembly of the thrust bearing shoes.

   The runner crown shall be bolted to the lower flange of the turbine shaft. A runner cone shall be provided and attached to the lower part of the runner crown to guide the water as it leaves the runner. The Contractor shall be responsible for the design of the coupling between the existing shaft and the runner. If any modification is necessary to the flange of the existing shaft, this work shall be performed by the Contractor. The Contractor shall provide all coupling bolts and nuts.

2. The runner shall be statically balanced before shipment. The residual unbalance shall be less than ____ foot-pounds.

(b) Kaplan Turbine

The runner shall be of the adjustable blade propeller type, __ inches (mm) in diameter at the centreline of blades, with blades automatically operated by the governor using oil pressure admitted to a servomotor located in the runner hub. The blades shall be balanced such that upon

loss of load and loss of governor oil pressure, the hydrodynamic and centrifugal forces acting on the blades will move them to their steepest position.

The blades shall be of one-piece construction with integral trunnions, or of separate blade and trunnion construction with corrosion-resistant bolts and seals. The use of blades bolted to trunnions will be acceptable only if the Contractor can provide evidence of at least 10 years of successful operating experience with this type of construction. If bolted design is proposed, the Contractor shall provide evidence of successful operation in his proposal. For bolted construction, detail stress calculations shall be submitted to the Owner. The outer edge of the runner blades shall be provided with anticavitation lips whose circumferential length shall be determined based on cavitation observations during model tests or based on experience with similar units if model tests are not performed.

The crosshead, links, hub, blades, and all rotating parts shall be adjusted in weight to provide accurate rotative balance of the completed runner. All runner surfaces in contact with water shall be machined and finished smooth by grinding and shall be free from irregularities such as hollows, cracks, projections, and porosity that may cause cavitation.

Dimensional tolerances, profile tolerances waviness, and surface roughness of all turbine parts which will be in contact with the water, shall be equal to or less than those parameters indicated by IEC Code, Publication No. 60193, Amendment No. 1, except for the surface roughness of the runner which shall not exceed the following values:

Surface	Surface Roughness Ra, Microinches
Trailing half of low-pressure side of runner blade inlet and outlet edges of the runner blade	125
Remaining runner blade surfaces	250
Runner hub	500

The runner hub shall be attached to the lower flange of the turbine shaft. The Contractor shall be responsible for the design of the coupling between the existing shaft and the runner. If any modification is necessary to the flange of the existing shaft, all expenses shall be included in the total contract price.

The hub shall be designed to withstand the forces of the blades and contain the blade operating mechanism, including the servomotor. The runner hub shall be designed to be full of oil under a pressure greater than that of tailwater. The pressure shall be maintained by a static oil column extending from the runner hub to the oil head. The Contractor shall furnish all governor and hub oil. The same type of oil shall be used in both the servomotor and hub.

A steel cone shall be attached to the hub of the runner to guide the water as it leaves the runner. If the servomotor is located in the cone, the cone shall be designed to support the runner, the shaft, and the (inner) (and intermediate) head cover assembly during erection. If the runner cone

contains oil, the connection of the cone to the runner hub shall be provided with dual 0-ring seals and provisions for pressure testing the seals. A corrosion-resistant valve shall be provided at the bottom of the cone for draining the oil from the runner hub.

The design and construction of seals or packings around the blade trunnions shall be such that the seals or packings may be easily replaced without removal of the runner and blade. All contact surfaces shall be stainless steel. The contact surfaces of the runner blade trunnions shall be polished to a 32 rms finish. The blade seals or packings shall be double-acting to prevent oil leakage from the hub and water entrance into the hub. After assembly, the runner shall be shop tested for any oil leaks in the presence of the Owner's representative, unless waived in writing. The bearings for the blade in the turbine hub shall be bronze, sleeve type bearings.

The hub shall be provided with an oil pressure operated double-acting servomotor to operate the runner blades. The piston of the servomotor shall be fitted with at least three cast iron piston rings to give uniform pressure to the cylinder walls and to prevent oil leakage. The servomotor shall be controlled by an actuator type governor. The existing governor oil pressure is specified in Section 1.3.2. Under the most unfavorable operating condition, the servomotor shall have sufficient capacity, including pressure losses, to supply the maximum force necessary to move the runner blades a full opening or closing stroke in 20 seconds; this shall be verified by test results and calculations submitted to the Owner. Blade servomotor travel shall be limited to the flattest angular position for on-cam operation to minimize off-cam runaway speed.

(c) Runner (Fixed Blade Propeller)

The runner shall be of the fixed blade propeller type. The blades shall be of one-piece construction either welded or bolted to the hub or integrally cast with the hub. The use of bolted blades will be acceptable only if the Contractor can provide evidence of at least 10 years of successful operating experience with this type of construction. The blade to hub bolted connection shall be designed to facilitate changing the blade angle in the field without dismantling the unit. Contractor shall provide a drawing showing field work required to make this change. For bolted construction, detail stress calculations shall be submitted to the Owner. The outer edge of the runner blades shall be provided with anticavitation lips whose circumferential length shall be determined based on cavitation observations during model tests or based on experience with similar units if model tests are not performed.

All runner surfaces in contact with water shall be machined and finished smooth by grinding and shall be free from irregularities such as hollows, cracks, projections, butts, and porosity that may cause cavitation.

Dimensional tolerances, profile tolerances, waviness, and surface roughness of all turbine parts which will be in contact with the water, shall be equal to or less than those parameters indicated by IEC Code, Publication No. 60193, Amendment No. 1, except for the surface roughness of the runner which shall not exceed the following values:

Surface	Surface Roughness Ra, Microinches
Trailing half of low-pressure side of runner blade, inlet and outlet edges of the runner blade	125
Remaining runner blade surfaces	250
Runner hub	500

The runner hub shall be attached to the lower flange of the turbine shaft. The Contractor shall be responsible for the design of the coupling between the existing shaft and the runner. If any modification is necessary to the flange of the existing shaft, all expenses shall be included in the total contract price.

A steel cone shall be attached to the hub of the runner to guide the water as it leaves the runner.

1.6 Runner Fabrication

(a) Francis Turbine

The selection of the runner fabrication method will depend on runner diameter and operating conditions. The runner can be manufactured using one or a combination of the following two methods:

Runner Fabrication Method	Runner Size
Fabricated from stainless steel plate One-piece stainless steel casting Stainless steel cast-weld fabrication	Size for each fabrication method will vary with head on runner and between suppliers

Note: One piece castings should be used only for small runners. In most cases for larger runners, a fabricated runner is preferred as it allows for better control of blade angles and profile tolerances.

The following describes several runner fabrication methods.

One-Piece Stainless Steel Casting

Small runners can be a one-piece stainless steel casting of ASTM A743 Grade CA6NM or equivalent. The runner casting shall be inspected by the Owner's representative before machining. All defects detected shall be removed, ground to sound metal and repaired by welding. No repair work shall be performed without the Owner's approval. Records shall be kept of all repair work and marked on shop drawings with copies provided to the Owner.

Cast-weld Fabrication

The runner shall be fabricated of cast stainless steel runner crown, band and blades welded together in the shop. The castings shall be ASTM A743 CA6NM, or equivalent. After weld

assembly, the runner shall be stress relieved by heat treatment. All welds shall be inspected by 100% ultrasonic testing. After machining, the welds shall be inspected by the dye-penetrant method.

The runner casting shall be inspected by the Owner's representative before machining. All defects detected shall be removed, ground to sound metal and repaired by welding. No repair work shall be performed without the Owner's approval. Records shall be kept of all repair work and marked on shop drawings with copies provided to the Owner. In some instances stainless steel plate may be used in lieu of castings with the approval of the Owner.

(b) Runner Fabrication (Kaplan and Fixed Blade Propeller Turbines)

Runner blades shall be one-piece stainless steel ASTM A743 Grade CA6NM castings or equivalent.

The runner hub shall be ASTM A27 Grade 70-40 or similar cast steel.

The cast blades will be inspected by the Owner's representative before machining. All defects detected shall be removed, ground to sound metal and repaired by welding. No repair work will be performed without the Owner's approval. Records shall be maintained for all repair work and shall be marked on shop drawings with copies provided to the Owner.

(c) Prototype to Model Homology Requirements

All replaced or modified components of the upgraded turbine shall be homologous to the model. The “permissible maximum deviations in geometrical similarity between prototype and model turbine” contained in IEC Publication 60193 should be called in the contract documents.

Checking of the homology on the upgraded runners and components shall be carried out during manufacturing or where appropriate after assembly of the components. The Contractor shall submit a detailed homology procedure at least 6 weeks before the start of any shop manufacturing. The procedure shall include, but not be limited to, the following:

- principal dimensions of the runner, outlet width between blades (Francis) and profiles of the crown, band, and blades.
- checks to include maximum blade thickness, runner seal lengths and runner seal clearances (at assembly).
- principle dimensions (including maximum thickness) and profiles of wicket gates and stay vanes if replaced or modified or of any other modified component. The end clearances of the wicket gates shall be checked at assembly.
- surface finish including waviness for all new or modified components.

1.7 Guarantees

1.7.1 Power Output

The maximum power output of the turbine with a new runner at the rated head specified in Section 1.3 shall be guaranteed to be not less than the output in the Data Schedules. Power values less than guaranteed will not be accepted. Power output shall be measured on the prototype as indicated in Section 1.8 of this specification.

If the turbine does not meet the power guarantee, the Contractor shall make all necessary modifications within a period of six months to comply with the guarantee. If, within this time period, the guaranteed power output is not reached, or, if by agreement between the Owner and the Contractor modifications are omitted, the Contractor shall pay the Owner US $___ for each kilowatt below the guaranteed value.

1.7.2 Efficiencies

(a) (When model tests are recommended.)

The guarantee on turbine efficiency will be met if the weighted average efficiency, WA, calculated from the model efficiencies corresponding to the required prototype plant sigma and scaled to the prototype conditions in accordance with the IEC Code, Publication No. 995, Section 3, Clause 5, is not less than the weighted average efficiency guaranteed by the Contractor. The turbine weighted average efficiency will be calculated using the following table of weighting coefficients and formula.

Operating Regime	1st Pt	2nd Pt	3rd Pt...	Last Pt
Net Head, ft				
Power Output, kW				
Weighting Coefficient				

The weighted average efficiency, WA:

$$WA = \frac{\Sigma(C_i \times \eta_i)}{\Sigma C_i} \qquad (\_\_\text{-}\_\_)$$

Where:

η_i = individual scaled model efficiency, and

C_i = the corresponding weighting coefficient in the previous table.

The efficiency deficiencies shall be calculated as follows:

$$D = W_g - W_m \qquad (\_\_-\_\_)$$

where:

$_g$ = refers to guaranteed efficiency,
$_m$ = refers to measured efficiency

If D is greater than zero without considering the tolerance on measurement uncertainty, the Contractor shall modify the model to attain the guaranteed value.

If the guaranteed value cannot be achieved by modification and if the Owner elects to accept the performance achieved, the Contractor shall pay the Owner a penalty of US $_____ for each unit for each 0.01% that the weighted average efficiency is below the guaranteed value. No bonus will be awarded for exceeding the guaranteed values. Should D be greater than 3%, the Owner reserves the right to reject the runner(s).

(b) (When efficiency is verified during Field Tests.)

The turbine efficiency guarantee will be met if the weighted average efficiency calculated from field test results is not less than the guaranteed value by the Contractor.

The calculation of weighted average efficiency from Field Test results shall be performed using the following table of weighting coefficients and formula.

Operating Regime	1st Pt	2nd Pt	3rd Pt...	Last Pt
Net Head, ft				
Power Output, kW				
Weighting Coefficient				

The weighted average efficiency, WA:

$$WA = \frac{\Sigma(C_i \times \eta_i)}{\Sigma C_i} \qquad (\_\_-\_\_)$$

where:

η_i = individual turbine efficiency, and

C_i = the corresponding weighting coefficient in the previous table.

1.7.3 Evaluation of Power Output and Efficiency in the Bidding Phase

The following method could be used to evaluate the bids received. However, if possible, the Owner should reserve the right to make adjustments to the bid prices as they see fit. The Owner

should be allowed some judgement in selecting the value of power and efficiency. The following section may therefore be left out.

(a) Power Output

The Total Bid Price will be adjusted if the guaranteed power output of the turbine with a new runner is above or below the arithmetical average of all power outputs guaranteed by all Bidders. An amount equal to US $____ will be added or subtracted from the Total Bid Price for each kilowatt that the turbine power output guaranteed is above or below the arithmetical average. The guarantee of turbine power output shall not exceed the maximum allowable generator input of ___ kW

(b) Efficiency

The Total Bid Price will be adjusted if the guaranteed weighted efficiency is 0.5% above or 0.5% below the arithmetical average of all weighted efficiencies guaranteed by all Bidders.

If the guaranteed weighted efficiency is greater or less than the average value ±0.5%, an amount of US $____ for each 0.01% of difference will be added or subtracted from the Total Bid Price.

1.7.4 Hydraulic Transients

(a) Overpressure

The maximum overpressure at the spiral case inlet following a unit load rejection under the most unfavorable conditions shall not be greater than the specified value. The Contractor shall demonstrate compliance with the guarantee through calculations and Site Commissioning Tests.

(b) Overspeed

The maximum overspeed during a unit load rejection under the most unfavorable conditions shall not be greater than the specified value. The Contractor shall demonstrate compliance with the guarantee through calculations and Site Commissioning Tests.

(c) Runaway Speed (Only when Model Tests are Prescribed)

The Contractor shall guarantee the maximum runaway speed under the most unfavorable operating conditions. Compliance with the guarantee shall be verified by model tests.

(d) Hydraulic Thrust

The Contractor shall demonstrate that the maximum hydraulic thrust for the turbine with a new runner does not exceed the design loading of the existing thrust bearing of ___ lbs (N). The Contractor shall provide with its Bid the maximum hydraulic thrust data for the turbine with a new runner.

1.7.5 Cavitation

(a) General

The runner shall be guaranteed against excessive material loss due to cavitation for a period of 8,000 operating hours or for two years, whichever occurs first, starting from the Date of Provisional Acceptance (Commercial Operation). The cavitation guarantee shall apply only if:

- The range of net heads and the minimum tailwater level remained within the limits specified in Section 1.3 of this procurement document during 98 (95)% of the operating hours; and
- Over the range of operating net heads the turbine is operated for not more than a total of 10% of the operating time for both of the following conditions:
  - Power outputs at maximum, minimum and rated net head greater than maximum power outputs stated by the Contractor in Section 1.3 for the respective net heads.
  - For all other operating net heads power outputs greater than maximum outputs produced using linear interpolation on the basis of the maximum power outputs at the maximum, minimum and rated net head.
  - Power outputs less than (50% for Francis, 20% for Kaplan, 70% for fixed blade propeller turbine) of the maximum outputs specified above for each operating net head.

The cavitation guarantee period will be repeated if the cavitation guarantees are not met.

(b) Cavitation Guarantee

If, within the guarantee period and specified operating conditions, the turbine runner or other parts become excessively pitted due to cavitation, the Contractor shall repair the pitted areas in a manner satisfactory to the Owner. Following repair, a new cavitation guarantee period will begin.

Excessive pitting of the turbine components and violation of the cavitation guarantee are defined if either of the following two criteria are exceeded:

- The removal of $0.1D^2/8000$ pounds of metal from the runner or $0.05D^2/8000$ pounds from the non-rotating components per operating hour; (D is the runner maximum outlet diameter in feet) or
- The pitting depth exceeds 3/16-inch (4.7 mm) over any single continuous area of 1 in^2 (6.25 cm2) or more.

The amount of pitting shall be determined in accordance with IEC Code, Publication No. 609.

During the cavitation guarantee period, the Contractor will be permitted to inspect the turbine. The first inspection of the runner and other parts subject to cavitation shall be performed at the end of the test run. Further inspection requirements will be determined by the Owner. During the cavitation guarantee period, the Contractor shall not modify the runner profile unless permitted by the Owner. The Owner may reject a runner if more than three repairs are necessary during

the guarantee period. For erosion or damage caused by suspended matter in water, the cavitation guarantee will not apply.

1.7.6 Shaft Runout

The maximum shaft runout as measured near the turbine and generator guide bearing shall not exceed ___ mils or the runout before any modifications to the turbine (whichever is greater) when operating at rated speed and within the full range of the required operating regimes. The CEA "Guide for Erection Tolerances and Shaft Alignment" can be used as a reference for acceptable runouts.

1.7.7 Design, Workmanship and Materials

The runner and other components affected by the turbine upgrade shall be guaranteed against all defects in design, workmanship, and materials for a period of 8000 operating hours, or two years from the date of provisional acceptance, whichever occurs first.

The runner will be inspected at the end of the test run. Further inspections will be carried out at the time determined by the Owner and prior to the expiration of the above-mentioned guarantee period. Such inspections will be performed by the Owner's personnel. For each inspection performed, the Owner will issue a report to the Contractor. If the inspection performed during the guarantee period should reveal the appearance of cracks in any portion of the runner or other new or modified turbine components, the Owner reserves the right to apply one of the following procedures:

- If the cracks or other defects are random without any systematic character, the Contractor shall eliminate or repair the defects.
- If the cracks and other defects exhibit systematic occurrences over the entire runner, or other turbine component, the Contractor shall propose a general repair procedure followed by heat treatment.

All repairs are subject to the Owner's prior review and acceptance of the repair procedure. The repairs shall be made at no cost to the Owner, and will be considered successful if they permit operation for a minimum of 8000 hours without the appearance of new cracks or other defects.

If, after repeated repair, new cracks should continue to appear, the Owner reserves the right to reject the defective parts.

1.7.8 Repairs by Contractor

During the guarantee period, all necessary repairs on the runner shall be performed by the Contractor at its own cost. Such repairs include, but may be not limited to, repairs to eliminate anomalies of metallurgical origin, such as casting defects or cracks, and repairs to correct surface quality of the runner blades and other turbine components damaged by cavitation. Normal

uniform wear due to erosion will not be considered as a fault to be covered by the specific guarantee.

1.8 Tests and Inspections

1.8.1 Tests

The Contractor shall perform at its expense all tests required to guarantee a satisfactory design and fabrication of the runner and other turbine components, as may be required. The tests shall include, but not be limited to:

- Model tests (if required)
- Quality assurance tests and inspections
- Commissioning tests

1.8.2 Model Tests

Refer to PROCUREMENT GUIDE FOR TURBINE MODEL TESTING - Section 2 of this Appendix.

1.8.3 Quality Assurance

The Contractor shall submit the Quality Assurance plan with the bid listing the corresponding tests and inspections to be performed and the acceptance criteria. The Owner will review the Contractor's Quality Assurance plan and may request necessary revisions during contract negotiations. Following award, the Owner will identify the tests that the Owner will witness.

All material required for the runners shall be tested to verify compliance with the applicable specifications. Tests shall be performed in accordance with the applicable standards. Ultrasonic and dye penetrant tests shall be performed on 100% of the runner. Full radiographic examination shall be performed where practical.

1.8.4 Commissioning Tests

Commissioning of the turbine with a new runner shall take place after successful completion of erection and the issuance of a "Complete and Ready for Commissioning Certificate" by the Engineer or Owner.

Commissioning the equipment shall consist of three test stages:

- Preliminary tests (dry tests) shall be performed when installation is complete, but before any rotation or admission of water, to ensure the complete and correct installation of the equipment.

- Pre-commissioning tests shall include filling all water passages and initial run and no-load tests without connecting the unit to the power system.
- Operation and performance tests shall be performed with the unit connected to the power system to ensure safe operation and to verify the guaranteed performance.

All instruments and measuring and recording equipment, including a multi-channel recorder to record the transient conditions during load rejection tests, shall be provided by the Contractor.

(a) Preliminary Tests (Dry Tests)

Preliminary tests shall consist of the following:

- Inspect the complete turbine water passage, including intake and draft tube to ensure removal of all foreign or loose objects which might cause damage, and verify the cross-sectional areas in the location of the pressure taps for acceptance tests.
- Adjust wicket gate and runner blades for uniform closure and sealing, dry test wicket gate (runner blade) closing and opening times, and calibrate wicket gate and runner blade servomotor stroke.
- Electrical check to assure correct wiring and cabling of all control, alarm, and auxiliary power circuits.
- Check the cooling water supply piping and control valves, and preliminary measurement of the cooling water flow.
- Preliminary adjustment of wicket gate and runner blade opening and closing times.
- Verify oil supply to all bearings and water supply to the shaft seal.
- Verify proper closure of all manhole and inspection covers.

(b) Pre-commissioning Tests

Pre-commissioning tests shall consist of the following:

- Slow filling of waterways while checking for leaks in the entire water system.
- Initial running of unit with stepwise increase of unit speed up to rated speed, observing bearing temperature trends, shaft runout, deflection of covers and bearing supports, and measuring vibrations.

(c) Operation and Performance Tests

Operation tests shall consist of the following:

- Synchronizing the unit.
- Preliminary load run and load rejection tests, determining overspeed and pressure rise at 60%, 90%, and full load rejections.

- The load shall be increased by steps and a load rejection made from each successively higher load up to the maximum load expected for the prevailing net head. At the completion of each load rejection test, the pressure rise and overspeed data shall be analyzed to ensure that the unit will not exceed the specified safety limits at the next higher load rejection.

During the load rejection tests, all precautions shall be taken to ensure that safe values of pressure and unit stresses will not be exceeded. Precautions may include setting the governor timing at rates slower than the design rates.

Subsequent to the operation tests, the following performance tests shall be performed:

- The output of each prototype turbine shall be determined by the indirect method in accordance with IEC Code, Publication No. 41 by measuring the generator output and adding the various electrical and mechanical losses. (*Owner may substitute ASME test code for this and other tests if preferred.*)
- Index tests by the differential pressure method in accordance with IEC Code, Publication No. 41, shall be performed on the prototype turbine. The tests shall be performed to determine the relative efficiency for at least five test points covering the full required range of turbine power outputs at selected head. Index tests shall be performed, if feasible, for the minimum, average, and maximum head. (For Kaplan turbines, index tests for each blade position shall determine the best wicket gate and runner blade relationship.)
- (When field acceptance tests are specified.)
  - General

    Acceptance tests will be performed in accordance with the latest edition of IEC Codes, Publication Nos. 41 and 198, and the following additional information and specifications. If the results of the tests indicate that turbine performance is below the guaranteed values stated in the contract documents, the Contractor will be given the opportunity to perform the necessary modifications to the turbine components and the tests will be repeated. The results of the second tests will be considered to be final for the purpose of the Contract. If the results of the acceptance tests show that the efficiency and other performance characteristics are below values guaranteed in the Contract, the Contract penalty provisions shall be applied.

  - Methods and Agreements

    The acceptance tests shall be performed on one unit.

    Tests shall be performed at the head available at the site, provided the head is within the prescribed head range.

    Although IEC Code, Publication No.41 states that no tolerances shall be considered for measurement uncertainties, often some tolerance is allowed. For example, the specification may state “when comparing the measured performance with the guarantees, test uncertainty per IEC Code, Publication41 will be allowed…”.

– Method of Measurement

The turbine performance characteristics shall be measured using acceptable methods of measurement in accordance with IEC Code, Publication No. 41.

– Test Results Conversion

All valid results of the field acceptance tests shall be adjusted to the net heads and power outputs required for evaluation of the turbine weighted average efficiency, all in accordance with Chapter 6 of the IEC Code, Publication No. 41.

– Efficiency Deficiency Calculation

The efficiency deficiencies shall be calculated as follows:

$D = WA_g - WA_m$ (__-__)

where:

$_g$ = refers to guaranteed efficiency

$_m$ = refers to measured efficiency

If D is greater than zero without considering any tolerance for measurement, the Contractor shall modify the turbine design to attain the guaranteed value.

If the guaranteed value cannot be achieved by modifications and if the owner elects to accept the performance achieved, the Contractor shall pay the Owner a penalty of US $ ____ per unit for each 0.01 of 1% that the weighted average efficiency is below the guaranteed value. No bonus will be awarded for exceeding the guaranteed values. If D is greater than 3%, the Owner shall have the option to reject the runner.

1.8.5 Test Run

After successful completion of all commissioning tests, all units shall be subject to a test run period, which shall last three months. After satisfactory performance of the equipment during commissioning tests and the test run period, a Provisional Acceptance Certificate will be issued by the Owner. On the date of issue of the Provisional Acceptance Certificate, the guarantee period will begin.

In the event the Owner and the Contractor agree to postpone or waive one or more commissioning tests, the beginning of the test run period would not be delayed. (In particular, this refers to the tests which cannot be performed until necessary headwater and tailwater conditions are available.)

2. Procurement Guide for Model Testing A (Francis) (Kaplan) (Fixed Blade Propeller) Turbine

2.1 General

The Contractor shall develop and provide a model homologous to the prototype machine to confirm the hydraulic design, determine the operating characteristics of the prototype and to verify the turbine performance guarantees. The Contractor shall furnish all materials, equipment, instruments, and labour required to construct the model and to perform the tests and measurements described herein. The model shall remain the property of the Contractor and must remain unchanged until the end of the guarantee period. The model may consist, fully or partially, of existing components.

The model shall be complete with spiral-case extension pipe (integral intake), spiral case (semispiral), stay ring, wicket gates, runner, and draft tube. The model shall be homologous to the prototype from the inlet section of the spiral case (integral intake) to the outlet reference section of the draft tube located at ___ feet (m) from the unit centerline.

The model shall be designed to allow visual observation of the runner cavitation patterns with a strobe light. The tests shall be performed at the Contractor's (independent) laboratory under test conditions equal to those specified in the latest edition of IEC Code, Publication No. 60193 (and/or 497) and all relevant supplements.

The model runner shall have an outlet diameter (*for Francis turbine*) or diameter at centreline of blades (*for Kaplan or propeller turbine*) of not less than 12 inches (300 mm), and the testing conditions shall be such that the Reynolds number is not less than 4×10^6. The Contractor shall include with the bid a detailed description of the test-stand facilities, methods of measurements, expected accuracies, and instrumentation, and shall give details of the model design as required in the Data Schedules.

The Contractor shall perform the preliminary model tests. When acceptable results are achieved, the Contractor shall send ___ copies of the Preliminary Model Test Report to the Owner for review. The Owner shall receive the report for review at least 25 days prior to the scheduled date for Witness (Acceptance) Tests. (*Choice of test type depends upon Owner's requirements.*)

Witness Tests shall be conducted by the Contractor in the presence of an expert designated by the Owner. These tests should verify the following:

- Test rig, the instruments used, and the model are in accordance with the relevant IEC codes to ensure reliability of the results.
- Guarantees are fulfilled.
- Results of the tests contained in the Preliminary Model Tests Report are correct.

The individual tests conducted during the Witness (Acceptance) Tests will be designated by the expert. The expert has the right to request those tests which he deems necessary to demonstrate

the Contractor's compliance with the pertinent parts of the procurement document. The Contractor shall submit outline drawings of the model to the Owner for review. The Contractor shall send ___ copies of the Final Model Test Report to the Owner for review.

2.2 Checking Model Geometric Similarity with Existing Prototype

The homology between the model and the existing prototype shall be checked by comparing the scaled down dimensions of the prototype with the corresponding model dimensions. Permissible deviations in uniformity and geometric similarity between the prototype and model shall be those stated in the latest edition of IEC Code, Publication No. 60193. (*However, if necessary, a list of stricter tolerances should be introduced.*) The surface finish of the model shall be in accordance with IEC Code, Publication No. 60193 and ISO Standard No. 1302 (1974) and will be subject to additional requirements stated in the Contract.

2.3 Guarantees and Penalties

2.3.1 Power Output

The prototype operating net heads, tailwater elevations, water temperatures, and project location are stated and shall be used in calculating the model parameters for these model tests.

Turbine Output: The turbine output shall be guaranteed to be ____ kW at a rated net head of ____ feet (m). The maximum output, stated by the Contractor, shall be guaranteed to be ___ kW at maximum net head and ___ kW at minimum net head. Steady-state power output of the turbine shall not deviate from the specified values and shall be achieved at the plant sigma corresponding to the minimum tailwater level without adding any measurement inaccuracy tolerance.

Should the Contractor fail to achieve the output guarantees, without adding any measurement inaccuracy tolerance, the Contractor shall undertake measures to fulfil the guarantees. If the guaranteed output stated cannot be achieved by a modification, the Owner reserves the right to reject the model.

2.3.2 Turbine Efficiency

The guarantee on turbine efficiency will be met if the weighted average efficiency, WA, calculated from the model efficiencies corresponding to the required prototype plant sigma and scaled to the prototype conditions in accordance with the IEC Code, Publication No. 995, Section 3, Clause 5, is not less than the weighted average efficiency guaranteed by the Contractor. The turbine weighted average efficiency will be calculated using the following table of weighting coefficients and formula.

Operating Regime	1st Pt	2nd Pt	3rd Pt...	Last Pt
Net Head, ft				
Power Output, kW				
Weighting Coefficient				

The weighted average efficiency, WA:

$$WA = \frac{\Sigma(C_i \times \eta_i)}{\Sigma C_i} \qquad (\_\_\text{-}\_\_)$$

Where

η_i = individual scaled model efficiency, and

C_i = the corresponding weighting coefficient in the previous table.

The efficiency deficiencies shall be calculated as follows:

$D = W_g - W_m$ (__-__)

where:

g = refers to guaranteed efficiency,

m = refers to measured efficiency

If D is greater than zero without considering the tolerance on measurement uncertainty, the Contractor shall modify the model to attain the guaranteed value.

If the guaranteed value cannot be achieved by modification and if the Owner elects to accept the performance achieved, the Contractor shall pay the Owner a penalty of US $_____ for each unit for each 0.01% that the weighted average efficiency is below the guaranteed value. No bonus will be awarded for exceeding the guaranteed values. Should D be greater than 3%, the Owner reserves the right to reject the runner(s).

2.3.3 Runaway Speed

The turbine maximum runaway speed at the most unfavourable combination of operating net head and wicket gate opening shall not exceed the value of ___ rpm. Should the run away speed exceed the guaranteed value, the Contractor shall modify the model design to fulfil the guaranteed value. If the maximum runaway speed cannot be achieved by the Contractor, the Owner reserves the right to reject the model.

2.4 Tests

2.4.1 Performance and Efficiency Tests

Model efficiency and performance shall be measured during model tests which shall be performed according to the relevant IEC codes except as revised herein. The test results shall be expressed in both model unit values and expected prototype values, using the formulas indicated in the latest editions of the relevant IEC Codes to scale up the results obtained from the model.

For Francis and Propeller Turbines

Model tests can be performed at constant speed of the model and shall be performed at cavitation coefficient representing the minimum prototype tailwater level. The model shall be tested at a discreet number of openings between the wicket gate opening corresponding to speed load at maximum net head up to and including 120% of the maximum prototype wicket gate opening. The maximum prototype wicket gate opening corresponds to the maximum opening at which the turbine delivers the guaranteed outputs.

The test results shall determine the head, power output, and efficiency relationships versus flow for each gate opening. The tests shall be performed for a head range greater than the operating range of the prototype.

From these curves, the following diagrams shall be prepared:

- Efficiency versus power output at the specified heads for comparison with guaranteed values.
- Power output versus wicket gate opening.
- Complete efficiency hill diagram.

The power output curve shall continue to a wicket gate opening of at least 110% of the maximum wicket gate opening.

For Kaplan Turbines

The same requirements for Francis turbines are valid for Kaplan turbines, with the addition that all the curves shall also be performed for several runner blade angles. The optimal relation between wicket gate opening and runner blade angle shall be determined over the range of operating heads.

(a) Acceptance Tests

Verification of power output shall be initially performed on the model; the Owner reserves the right to confirm the output on the prototype during Field Acceptance Tests. Power output for the model which does not meet the guaranteed values will not be accepted. Power output tests shall be conducted on each prototype to verify the guarantees. Should the results of the Field Tests

indicate that the output guarantee is not fulfilled, the relevant guarantee and contractual provisions will apply.

The individual values for turbine efficiency for the prototype shall be stated. Verification of the efficiency guarantee shall be accomplished by the model test. By applying the scale-up formula as indicated in the latest editions of the relevant IEC Codes, the complete table of prototype efficiencies shall be derived and evaluated as described herein.

If the combined weighted average efficiency determined from the model test results does not meet the guaranteed value, and the Contractor is not successful in improving the model to achieve the guarantee within three months from the Acceptance Tests, the Owner will have the right to choose between rejecting the model or requiring the Contractor pay the penalties. The Owner reserves the right to perform efficiency tests on the prototype if, in its opinion, proof exists indicating that the similarity between model and prototype has not been achieved. If the results of such a Field Test show that the guaranteed efficiencies are not fulfilled, all relevant guarantee and contractual provisions will apply and the Contractor shall also pay the costs of the Field Tests.

2.4.2 Runaway Speed Tests

Runaway speed tests shall be performed for different wicket gate openings (and runner blade angles) to determine the rotational speed for which the turbine model torque has zero value. Based on the results of these tests, the prototype turbine runaway speed shall be calculated for the maximum prototype head and other heads, as may be required, and for wicket gate openings up to 120% of the maximum prototype wicket gate opening.

(a) Verification of Guarantees

The maximum runaway speed guarantee shall be compared with the maximum runaway speed determined on the basis of model tests for the most unfavourable combination of the prototype head, plant sigma, wicket gate opening (and blade angle) to confirm that the runaway speed guarantee has been met. The result will be accepted only when the value of runaway speed is less than or equal to the guaranteed value without considering possible friction and windage losses of the prototype.

2.4.3 Cavitation Tests

During cavitation tests, the efficiency versus cavitation factor sigma curves will be determined for the full range of model regimes corresponding to the required range of prototype wicket gate openings and operating heads. The Contractor shall also prepare cavitation characteristic curves for the turbine operating range, showing the sigma zero (sigma standard) factor versus model characteristic parameters and wicket gates openings (and runner blade angles) (as for the efficiency hill diagram) and runner blade angles). Refer to IEC Codes, Publication Nos. 193A or 497.

Furthermore, for selected operating conditions, including at the extremes of the operating range, the photographs of the runner and sketches drawn from visual observation shall be prepared.

The Owner reserves the right to reject the model if the following cavitation conditions are not met on the model:

- The difference between plant sigma and sigma standard, as defined by IEC Code, Publication No. 193A, is higher than specified values for the required range of operating regimes.
- At plant sigma, the runner blades are free of significant visual cavitation for all required regimes.

During cavitation tests, the development of cavitation and vortices shall be observed by a strobe light, and their significance shall be evaluated. Typical cavitation observations showing the location, extent, type, and intensity of cavitation for representative sigma values, including those at plant sigma and at sigma standard, shall be recorded by photographs and sketches. During cavitation tests, the air content in the water shall be carefully monitored. Totally degasified water will not be accepted during the tests.

2.4.4 Pressure Pulsations in the Draft Tube

Pressure pulsations shall be measured for model regimes corresponding to different prototype heads and wicket gate openings from 30% to full gate (and different blade angles). Frequency analysis of pressure pulsations shall also be conducted. The maximum prototype RMS draft tube pressure pulsations predicted from the model for wicket gate openings between 40% and full gate, under prototype head and tailwater conditions, shall not exceed 5% of the prototype head. If such amplitude is exceeded at any point, the manufacturer shall study and test devices to reduce the pressure pulsations. Such devices will require approval from the Owner before use. If a device to reduce the pressure pulsations is used, its effect on the turbine efficiency shall be studied and the additional model tests required by the Owner shall be performed at no additional cost to the Owner.

2.4.5 Wicket Gate Torque (Runner Blade Torque) *(Measured only in Special Cases)*

Wicket gate (and runner blade) torque tests shall be performed to establish that the results, when converted to prototype values, stay within guaranteed values and are considered in the structural design of the unit. The wicket gate (and runner blade) torque shall also be measured beyond the region of normal operation which can occur during transient conditions up to runaway. The wicket gate torque shall also be measured simulating misalignment of one wicket gate. The wicket gate torque effect on the misaligned gate and on the two adjacent gates shall also be measured.

2.4.6 Hydraulic Thrust

2.5 Test Report

After the preliminary model tests have been completed, the Contractor shall prepare and send a detailed test report to the Owner for review. The Preliminary Model Test Report shall include the following:

- Complete description of the test stand including drawings, schematics, and photographs.
- Model drawings showing the dimensions of the model hydraulic components and clearances.
- Table of prototype and model conditions.
- Description and drawings of measuring instruments including estimated measurement accuracies.
- Procedure used for calibrating the measuring instruments and current calibration documentation to demonstrate accuracy.
- List of symbols and formulas used for calculating the characteristic coefficients and scaling the model performance characteristics to the prototype conditions.
- Sample calculations used for the test results for all tests.
- Official standard institute certificates to state the accuracy of the instruments used for calibration.
- Model characteristic curves covering and exceeding the full range of pump operating conditions.
- Model characteristic curves covering and exceeding the full range of turbine operating conditions. A model turbine efficiency hill diagram shall be included.
- Expected turbine performance curves of the prototype for various wicket gate openings for the full range of specified heads; the results shall include the head for maximum turbine efficiency.
- Sigma cavitation break curves and composite cavitation diagrams.
- Cam profile curves showing relationship of blade and gate position (Kaplan).
- Photographs and sketches of runner during cavitation tests.
- Wicket gate torque characteristics and blade torque characteristics.
- Diagrams of draft-tube pressure fluctuations.
- Characteristic curves of runaway speed
- Check sheets to record model dimensions.

A draft of the test report shall be submitted to the Owner for review at least 25 days prior to the Witness Tests. The Final Model Test Report, including the Witness Test results, shall be

prepared by the Contractor and submitted to the Owner for review within four weeks following completion of the Witness Tests.

2.6 Model Test Improvement

Should the model tests show that the expected requirements are not met or that the prototype would not meet the guaranteed performance and efficiencies, the Contractor shall make any changes and furnish new parts, or prepare a new model, if required, to obtain results that meet all requirements. All expenses involved and retesting costs shall be borne by the Contractor.

3.0 Guidelines for Governor Procurement Specifications

There are three main categories of governors:

(a) mechanical - hydraulic governors

(b) analogue electric-hydraulic governors

(c) digital electronic hydraulic governors

Governors are used to control the position of turbine wicket gates, runner blades on Kaplan turbines and deflectors and needles on Pelton turbines. It is not possible within the scope of these guidelines to provide sample specifications for all governor types. Furthermore, governor specifications should be written by an expert in the field as the technical issues can be quite complex. The following information is an overview of the technical specifications for the key components in a governor procurement contract. The topics are presented in the style of technical specification for clarity and organization.

The requirement for governing in a transmission system is dependent upon the performance requirements of the applicable Regional Transmission Organization (RTO), e.g. WSCC or other regulatory councils such as the North American Electric Reliability Council (NERC), which is made up of ten reigonal councils. The governor characteristics must comply with the standard issued by these local authorities. Regular testing of governors and generators is often mandatory.

Sample text and examples are provided under many of the topic headings to illustrate the type of information required. The examples used for governor control and actuator topics are for a governor replacement project on a Francis unit involving replacement of older model mechanical-hydraulic governor equipment up to the distributing valve with digital type governor control. The specification guidelines for the Kaplan and Pelton specific components are taken directly from IEEE Standard 125 "IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Turbines" with some small additions.

There are many governor specification standards available. IEEE standard 125 provides guidelines for all parts of the governor system. EPRI also has published guidelines for hydro-

mechanical equipment specifications which are a useful resource for the preparation of governor specifications.

The following guidelines are by no means exhaustive but they do cover most of the main technical issues for governor procurement contracts.

3.1 Governor System Type

3.1.1 Definition of Governor

Define what the term "governor" and "governing system" mean in the contract. For a total replacement of an existing system, for example, it may include speed sensing elements, governor control actuator, the hydraulic pressure supply system and the turbine control servomotor.

Example (Replacement of part of governing system including the distributing valve):

For example: the terms "governor" and "governing system" shall for the purpose of this Contract include the digital control, hydraulic actuator, and distributing valve according to their combined effect on the governing performance of the turbine-generator.

3.1.2 Description of Governor System

Provide a description of the new or replacement governor.

Example (Digital Governor):

The replacement governor shall be a parameter programmable microprocessor-controlled PID electric-hydraulic type, with compatible hydraulic actuator and distributing valve. The governor shall provide speed regulation and stable closed-loop control using a digital algorithm utilizing Proportional, Integral and Derivative ("PID") gain elements and electrical circuits to provide a final current-loop control signal which powers the pilot servo transducer and controls the oil distributing valves which ultimately control and position the wicket gate servomotors of the hydraulic turbine. It shall accept a speed sensing voltage signal from a single phase potential transformer (PT) on the generator.

Power for the electrical portion of the system shall be obtained from the __ VDC station battery. The governor shall be designed and equipped for starting the turbine locally or from a remote point, controlling and adjusting speed when operating isolated (off-line), for manual or automatic synchronizing of the unit with the electrical system and for controlling the power delivered by the unit when synchronized (on-line).

3.1.3 Main Functions

Describe the main functions of the governing system for the application.

Example:

The governor shall be designed and equipped to control the speed and/or power output of the unit

- as an individual isolated unit,
- in parallel with any number of other units using a speed regulation (droop) characteristic.

3.1.4 General Arrangement

Provide a description of how the equipment is to be arranged. Governors can be packaged in various arrangements. Three common configurations are:

1. gate-shaft type
2. actuator type
3. cabinet type

Example (Digital Governor):

The governing system shall include a digital control utilizing a microprocessor (computer). The digital control shall be either a fixed capacity (non-expandable) design or a modular bus-connected design provided that all requirements of the Contract are met. The digital control shall input signals of speed, power, relay contact logic (such as raise and lower commands) etc. and calculate, using the PID and other algorithms, the required actuator position, panel meter signals, and relay output states. It shall transmit the necessary outputs to control hydraulic amplifiers, panel meter readouts, output relays etc.

In addition, the digital control shall provide communication using the _____ communication protocol for start, stop, dynamic parameter adjusting, and status reporting (monitoring) of the governor.

A display and keypad in the digital control shall provide the interface between the operator and the governor. The digital control shall provide for reading and adjustment of parameters and settings and presentation of self-diagnostic results by exception reporting. Panel meter readouts (indicators) shall be provided as per Section ___ "Governor Control and Indication."

The governing system shall be housed in two separate enclosures, each provided with access doors for adjustment and maintenance of the equipment. One enclosure shall contain all of the electric-hydraulic parts of the governor system including hydraulic actuator and distributing valve, hereinafter referred to as the "governor actuator cubicle" or just "actuator cubicle." The other enclosure shall contain the electrical control circuits, display and keypad and hereinafter be referred to as the "digital governor control" or just "governor cubicle." The front panel of the governor actuator cubicle shall in any case be provided with a section for mounting the panel meter readouts, lamps and controls as specified herein.

3.2 Control Modes

State the control modes required.

For example:

1. load (MW) control
2. Load-frequency control
3. Frequency control
4. Automatic frequency matching
5. Actuator lock free control

3.3 Capacity and Timing

3.3.1 Governor Capacity

Sample Text:

The governing system shall be capable of operating the turbine servomotors through a full opening and/or closing stroke in the minimum times specified in the BASIC PARAMETERS. For hydraulic actuation, the governing system shall meet the minimum times specified starting with the minimum operating oil pressure in the governor pressure tank and with the maximum net head on the turbine. A full stroke is defined as the servomotor travel between zero and 100% travel.

3.3.2 Servomotor Rate Timing

Sample Text:

The operating time for both the opening and closing strokes of the servomotors shall be independently adjustable within the range specified in BASIC PARAMETERS. It shall be possible to make adjustments while the governor is in operation without disassembly of any part of the governor. Secure and positive means of locking the adjusting devices shall be provided. It shall not be possible for the servomotors to move at a rate faster than the maximum rate specified, i.e. the stoke times shall not be less than the minimum values specified.

3.3.3 Seismic and Ambient Conditions

Specify the seismic design criteria and pertinent information on the ambient conditions to which the governor will be exposed.

3.4 Basic Parameters

The following are detailed specifications and other pertinent data that should be specified for the turbine speed governing system:

3.4.1 Turbine Data

1. Type of Turbine
2. Size
3. Rated Head
4. Rated Speed

3.4.2 Type of Governing System

Mechanical-hydraulic governors are usually not specified for governor replacement projects. These 3 main categories of governors are:

1. mechanical-hydraulic (ball-head motor)
2. analogue electric
3. digital electronic

The governor type should be fully described.

3.4.3 Required Governor Capacity (for hydraulic actuation)

1. Normal Operating Oil Pressure of Servomotors
2. Minimum Stall Pressure
3. Maximum Oil Velocity in Pressure Piping
4. Number of Gate Servomotors
5. Maximum work capacity

3.4.4 Servomotors Stoke Timing

Closing Full Stroke	Adjustable Recommended
Opening Full Stroke	Adjustable Recommended
Stroke Length	

3.4.5 Turbine-Generator Dynamic Data

Moment of Inertia	WR^2 = _____
Machine Mechanical Start Time	

3.4.6 Penstock and Surge shaft Data

1. Surge Shaft Type
2. Penstock Dimensions
3. Water Starting Time
4. Net Head Range

3.4.7 Electric System Frequency Variation

The steady-state frequency of the electric power system may vary between the limits of ___% and ___% of the ___ Hz rated frequency. The governing system shall enable operation of the unit up to full load over this frequency range.

3.5 Governor Performance

The following are performance characteristics that should be described in detail in the specifications. Sample text is provided.

Sample Text

The governor shall be designed to meet the characteristics of performance itemized below. The governor shall be tested to prove that the values stated in the Contract have been achieved.

3.5.1 Stability

The governor shall control and regulate, with an adequate margin of stability, the speed of the turbine over the full frequency range of the system stated in the BASIC PARAMETERS, and at all power levels from no-load up to the maximum power over the full range of net head. Without restricting the generality of the foregoing, the governing system shall meet the following, minimum requirements:

(a) Sustained conditions

Speed Stability Index:

The magnitude of the envelope of the steady-state speed oscillation caused by the governor system shall not exceed ____ percent of rated speed with the generator operating at rated speed with no-load, and/or at rated speed with a constant isolated load with the governor speed regulation (droop) set at ___%.

Power Stability Index:

Excluding the effects of system frequency deviations and transient hydraulic surges, the magnitude of the envelope of the steady state output power oscillation caused by the governor system shall not exceed __% of the rated power of the unit with the generator operating in parallel with other generators in an integrated multi-plant power system to supply a constant load with the governor speed regulation (droop) set at __%.

(b) Dynamic Conditions

Full Load Rejection:

Following rejection to zero of any load within the capability of the governed turbine-generator unit, speed shall be returned to the speed reference as may be modified by speed regulation, with no more than one underspeed deviation not to exceed __% of rated speed and one overspeed deviation not to exceed __% of rated speed subsequent to the initial overspeed deviation.

Rejection and Acceptance or Isolated Load:

The governor shall be adjusted to provide suitably damped control of speed when the turbine-generator unit operates into an isolated 1.0 PF load. The following criterion shall be used to judge the adequacy of damping provided by the governor:

The second speed deviation of the same sign as the first speed deviation shall be attenuated to less than __% of the first speed deviation following a step load change (increase or decrease) of __% of rated power of the unit while the turbine is operating initially at __% of rated power at rated net head, at rated speed and with a governor speed regulation (droop) of __%.

(c) Frequency Response

The range and effectiveness of the primary damping system of the governor shall be such that the open loop frequency response of the governor and turbine from the speed input to the turbine shaft speed output at the least stable operating point and at signal levels within the linear response range shall exhibit the following characteristics:

- The gain margin at the phase crossover frequency shall be adjustable between __ dB and __ dB.
- The phase margin at gain crossover frequency shall be adjustable between __ ° and __ °.

3.5.2 Control Characteristics

(a) Governor Transfer Function

The electrical circuits and software which perform the functions of speed regulation and power regulation shall comprise two separate and independent three-element (Proportional, Integral, Derivative) governing networks. The speed regulation operation shall be entirely independent of, and unaffected by, power regulation operation and vice-versa. The output of each element shall not saturate in the full input range up to full load rejection overspeed. The gain or time constant of each element shall be continuously and independently adjustable over the following ranges and shall be capable of at least providing the specified regulation gain margin and phase margin.

Speed Regulation (Droop):

The speed regulation (droop) shall be adjustable between zero and __%. This is the percent of speed setting drop from the minimum MW to the maximum MW load.

Proportional Element:

The proportional gain, which is the ratio of the proportional element's per unit output to its per unit input, shall be adjustable from at least 0 to __%.

Derivative Element:

The derivative gain, which is the ratio of the derivative element's per unit output to the time derivative of that element's per unit input, shall be adjustable from at least 0 to __ seconds.

Integral Element:

The integral gain, which is the reciprocal of the time required for the integral element's per unit output to be equal in magnitude to that element's per unit input where that input is a step function, shall be adjustable from at least 0 to __ per second.

(b) Speed Setting Adjustment

The speed setting of the governor shall be operable and functional only when the turbine-generator is disconnected from the electric power system, i.e. tie breaker or unit breaker open.

The speed of the turbine-generator under control of the speed setting shall be continuously adjustable from __% of rated speed at no load to __% of rated speed at no load.

The off-line speed setting shall be saved for later use while the unit is synchronized with the electric power system.

Speed setting shall be independent of governor power regulation (droop).

(c) Power Setting Adjustment

Power setting of the governor shall be operable and functional only when the turbine-generator is connected to the electric power system, i.e. unit breaker closed.

The output power of the turbine-generator at rated speed under control of the power setting shall be continuously adjustable between 0% and __% at rated generator output at 1.0 PF.

Power setting shall be independent of governor speed regulation (droop). The output of the power adjustment compensation shall be summed with the output of the speed stabilization at or ahead of the electric-hydraulic transducer.

The rate of change of the power setting adjustment, both raise and lower, shall be limited with a rate limit function having a programmable rate limit as specified under the Section 2.05 GOVERNOR CONTROL AND INDICATION.

(d) Isolated Load (Islanded) Operation

Special provisions shall be provided for isolated load operation. This is defined as the case where the governor breaker is closed and the unit is supplying a local load within the unit's capacity and a remote tie breaker used for connecting the unit and the local load to the infinite bus system is open. In this case the following mode of operation shall be expected:

- The MW droop shall be forced to __% droop for isochronous operation using the open state of the remote tie breaker.
- The PID gains shall be those required for on-line regulation for both the speed regulation and the power regulation loops.

(e) Speed Dead Band

The speed dead-band is defined as the magnitude of the steady-state speed deviation from rated speed within which there is no measurable change in the position of the wicket gate servomotor.

The speed dead-band for the governor system shall not exceed +/-__% of the rated speed of the turbine at any wicket gate opening.

(f) Dead-Time

For an instantaneous load change of more than __% of the rated power of the turbine, the dead-time, which is defined to be the elapsed time from the initial speed change to the first movement of the turbine control servomotors, shall not exceed __ seconds.

(g) Automatic Wicket Gate Opening Control

When the automatic sequence control is engaged for start-up, the time required from the beginning of wicket gate movement from the closed position until rated speed is achieved shall not exceed __ seconds, after which period the automatic unit start sequence control will initiate field flashing and synchronizing. This requirement shall be met throughout the full range of turbine operating heads.

3.6 Governor Control and Indication

The control and indication arrangement of governor is highly customized. The following are some control and indication items to consider:

3.6.1 Governor Adjustments

Discuss how displays are controlled i.e. by a control key pad.

3.6.2 Gain Change-Over

Request a means for automatically switching the gains of the PID speed regulation circuits of the governor as required to suit isolated (off-line) and synchronized to the system (on-line) operating using the remote tie breaker.

3.6.3 Speed Setting Adjustment

State how speed setting shall be adjustable e.g. by the digital control keypad and by raise/lower contact inputs.

Sample Text:

The display shall indicate the position of the speed setting device to __%or better of the speed setting from __% to __% of normal speed.

3.6.4 Power Setting Adjustment

The power setting adjustment display shall indicate in megawatts to the nearest __ MW.

The __ to ___% power setting adjust time shall be variable between __ and ___ seconds (or ____ to _____ MW per second or ___ to ___% per second).

3.6.5 Wicket Gate Limit Control

The wicket gate limit shall limit the wicket gate opening to any position within the full stroke while the unit is in operation. The full travel time of the gate limit adjustment shall be variable between __ and __ seconds (or ___ to __% per second).

(a) Wicket Gate Servomotor Position Transducer and Limit Switches

Describe the device that gives indication of the wicket gate servomotors position.

(b) Wicket Gate Position and Limit Indicators

Discuss type of indicators required and where they should be mounted.

(c) Automatic Wicket Gate Control For Start-Up

The governor shall include an automatic gate opening for start-up which shall make it possible to accelerate the unit to near rated speed in the shortest practical time without overspeed.

In the range of __% to __% of rated speed, the speed change shall not exceed __% per second to permit automatic closure of the generator circuit breaker when rated speed is achieved. If the unit speed should exceed the rated value because the automatic synchronizer fails to close the generator circuit breaker on the first pass, then the control of speed adjustments will be taken over by the automatic synchronizer.

After synchronization the unit shall be operated at speed-no-load.

(d) Turbine Speed Indication

Indication of turbine speed in revolutions per minute shall be provided in two locations.

(e) Unit Reset, Start, and Stop (Complete Shutdown)

The governor shall provide control functions to enable resetting, starting, synchronizing and complete shutdown of the turbine. Reset, start and stop functions shall be initiated by external contact closures.

An emergency shutdown push-button assembly shall be provided.

(f) Partial Shutdown (Speed-No-Load) Signal

Example:

The governor shall provide a start gate limit function which shall limit the opening of the gate servomotors, or return it to a position slightly above the speed-no-load position. The limit position shall be adjustable.

The start gate limit function shall not disturb the normal speed governing functions of the governor below the limit position.

(g) Generator Brake-Air Solenoid Valve (if required)

Example:

An electrically operated solenoid air valve shall be provided for the generator air brakes, complete with the necessary controls to provide automatic control of any braking sequence. Automatic operation shall be possible at any speed below __% of the specified synchronous speed, provided the wicket gates are fully closed.

(h) Generator Brake-Air Line Pressure Switches (if required)

For annunciation of low supply air-pressure and interlocking an adjustable pressure switch shall be provided in the brake supply air line to the brake-air solenoid valve.

(i) Governor Oil Pressure Switches

Discuss type of switches required.

(j) Pressure Gauges

Example:

All gauges shall be graduated in SI and Imperial units.

Gauges required may include:

1. Generator brake-air pressure gauge
2. High pressure supply oil gauge
3. Control oil gauge (low pressure)
4. Penstock Pressure

(k) Remote Control and Indication

State the requirements for wiring to external terminals to permit remote controls of such items as:

1. Speed setting adjustment
2. Power setting adjustment
3. Unit start, reset and shutdown
4. Wicket gate time adjustment

Sample Text:

Provision shall be made for remote metering of governor functions at the ____. The Contractor shall supply the necessary instruments. Indicators shall be in square flush mounting matte-black cases (approximately __ mm in diameter) with white dials and black scales, legends and pointers.

Indicators may include:

1. Speed Setting Indication
2. Wicket Gate Position/Limit Indication
3. Turbine Speed
4. Governor Oil Supply Pressure
5. Penstock Pressure

(l) Speed Signal Source1

Speed sensing methods using electrical devices produce either voltage or frequency output proportional to speed:

Voltage output methods include:

1. Small DC generator with a permanent magnet field.
2. Small permanent magnet alternator whose output is rectified with the DC voltage used to generate a speed sensing signal
3. Dedicated PT's on the generator's output-terminals.

Frequency output devices suitable for electric (analogue) and digital governors include:

[1] "The Guide to Hydropower Mechanical Design", American Society of Mechanical Engineers, HCI Publishers Inc., 1996.

4. Either a permanent magnet alternator or generator output voltage feeds into a frequency sensitive network that provides a signal proportional to speed deviation from equilibrium.

5. Speed sensor with a toothed wheel and magnetic pick-up on the turbine shaft or driven by an auxiliary shaft and coupling. The output frequency of the pick-up is measured by the speed sensor.

Detailed specifications of the preferred speed sensing method should be provided.

Examples:

1. A dedicated single phase potential transformer (PT) located on the generator's output terminals will be used to generate the speed signal. Loss of speed signal shall cause the unit to shutdown.

2. The Contractor shall supply a speed signal generator (SSG) to develop a signal proportional to the speed of the turbine as a standby to the speed signal from the generator PT. The speed signal shall be used by the speed sensing element of the governor and be compatible with all governor performance requirements.

The speed signal generator shall be directly driven by an extension to the generator pilot exciter shaft using suitable couplings. It shall be designed to all for vertical and radial movement of the shaft and for vertical jacking of the shaft, up to ___ inches (__ mm), for thrust bearing maintenance without the need for dismantling any portions of the speed signal generator.

The speed signal generator shall also be equipped with 3 mechanically activated speed switches.

Overspeed	___% accelerating
Brakes (lockout)	___% decelerating
Brakes (non-lockout)	___% decelerating

(m) Speed Switches

The Contractor shall provide __ electrically operated speed switches, actuated by the governor speed sensing circuit. One primary overspeed switch and ___ auxiliary switches. The switches shall be capable of maintaining the accuracy of their setting within __% of rated turbine-generator speed and unless otherwise noted shall be field adjustable. The switches shall be adjustable over the range 0 to __% of the specified unit speed.

The primary speed sensing relay or circuit shall be arranged for hysteresis operation to preclude any possibility of intermittent contact operation at the point of pick-up or drop-out. The differential between pick-up and dropout or vice-versa shall not exceed __% of the rated speed of the turbine-generator.

(n) Mechanical Restoring (if required)

Provide technical specifications for the mechanical restoring, i.e. connections between the governor and the servomotors (depends on mechanical governor type).

The Contractor may elect to adapt the existing mechanical restoring for the new governor or replace it with new mechanical restoring.

(o) Hydraulic Hand Control

Option:

The manually operated transfer switch shall enable hand control, using an operating knob, of oil pressure to the wicket gate servomotors such that the gates are forced to follow the limit control independent of turbine speed. Assuming that an adequate supply of high pressure oil is available, the hand control shall not require the use of normal electronic or electric-hydraulic portions of the governor.

Operation of the manually operated transfer switch shall preclude movement of the wicket gates due to operation of the electric-hydraulic transducer either by electrically blocking the transducer's input or by mechanically blocking the transducer's output. A contact, which closes when the transfer switch is operated, shall be provided to indicate that the governor is in hydraulic hand control.

(p) Electronic Hand Control

Option:

The manually operated transfer switch shall enable an electronic hand control to operate the wicket gate servomotors, independent of turbine speed. Assuming there is a separate DC power supply (DC-DC converter), the electronic hand control shall not require the use of normal digital electronic portions of the governor digital control. This signal will be used to operate the transducer on the actuator, which in turn will manipulate the hydraulics to operate the servomotors.

Operation of the manually operated transfer switch shall preclude movement of the wicket gates due to the digital control's output signal to the electric-hydraulic transducer by electrically blocking the output of the former. A contact, which closes when the transfer switch is operated, shall be provided to indicate that the governor is in electronic hand control.

(q) Shutdown Solenoid

The governing system shall be equipped with an electrically operated solenoid to permit start and stop operations to be made from a location remote from the governor actuator cubicle. When de-energized the solenoid shall initiate complete closure of the wicket gates at the maximum allowable rate, assuming that an adequate supply of high pressure oil is available. The shutdown

solenoid shall cause the wicket gate servomotors to close without the use of normal electronic or electric-hydraulic portions of the governor.

The shutdown solenoid will be used for automatically shutting down the turbine upon overspeed, failure of governor oil pressure, excessive temperature of the main shaft bearings, or upon operation of any of the automatic protective features in connection with the main generator, exciter, pilot exciter, and/or transformers. The solenoid shall consist of dual coils rated for continuous service at ___ VDC and provided with at least ___ electrically independent Normally Open contacts.

The solenoid shall also be furnished with a manual operating handle and mechanical lock, or equivalent provisions to enable the operator to manually lock it in the RUN position.

A manual interlock switch having one Normally Open and one Normally Closed electrically independent contacts shall be provided which shall open the solenoid control circuit and energize indicator lamps whenever the shutdown solenoid has been operated manually. The interlock contacts shall be capable of interrupting the inductive load current of the solenoid.

(r) Kaplan-Specific Control Specifications2

Adjustable Blade Control

General: For adjustable blade type turbines the necessary controls shall be provided to position the turbine runner blade sin accordance with the turbine manufacturer's requirements for an optimal relationship between the gates, blade angle, and head. The control shall be arranged such that upon loss of governor oil pressure the blades are allowed to move to the position of steepest pitch.

Blade Controller: A controller shall be provided to program the optimal blade position as a function of main servomotor position and head. The steady state blade position shall not be deviated by more than 1% of full scale from the required value over the full range of main servoomotor position and over the full range of head.

Blade Lock Solenoid: A solenoid operated device shall be provided that, when energized/de-energized, shall prevent further moment of the turbine runner blades. This device shall main the fixed runner blade position regardless of normal hydraulic fluid leakage in the control system, turbine fluid head, or blade servomotor.

The solenoid may be interlocked through the following devices:

- governor hydraulic fluid pressure switch
- blade angle position switch
- turbine fluid head level switch

[2] IEEE Standard 125 "IEEE Recommended Practice for Preparation of Equipment Specifications for Speed - Governing of Hydraulic Turbines Intended to Drive Electric Turbines

- blade tilt solenoid auxiliary switch

Manual Control: A manual control for runner blade position shall be provided that will disable the blade control and make it possible to set and hold the blade angle at any pitch for test purposes

Blade Angle Indicator: A blade angle indictor shall be supplied at the governor to show the position for the turbine runner blades. The blade angle indicator shall be field-calibrated to show runner blade angular position as a percentage of full range.

(s) "Pelton-Specific Control Specifications3

Impulse Turbine Needle(s) and Deflector(s) Control: Controls shall be provided within the governing system to position the turbine needles and jet deflectors as required to control the impulse turbine in accordance with the specification. The difference in position between any two needles or between any two deflectors shall be less than 1% of full scale over the full operating range.

Under normal conditions, the needles shall control the flow of water to the turbine and the needles of all nozzles in services shall operate simultaneously, except when the number of needles in services is variable.

The deflector operation shall be coordinated with the needle operation so that upon an increase in speed a position of each jet will be quickly deflected until the needles have closed a sufficient amount to allow passage of only enough water to maintain speed and power with the deflectors out of the stream. The deflectors shall enter the jets when the rate of load change is faster than can be handled by the needles.

3.7 Electrical specifications and ratings

Detailed specifications should be provided for the following:

3.7.1 Power Supply Voltage

Refer to the Section 2.08 POWER SUPPLIES.

3.7.2 Potential Transformer (PT) (if selected or the source of the speed signal)

Nominal Voltage

Range

[3] IEEE Standard 125 "*IEEE Recommended Practice for Preparation of Equipment Specifications for Speed - Governing of Hydraulic Turbines Intended to Drive Electric Turbines"*

Nominal Frequency

Range

Nominal Burden

Contractor to specify burden rating if different from above.

3.7.3 Digital Control Input Contacts

The digital control shall accept, relay contact control signals for integration of the governor into the unit's control system. Some of the control signals may include:

1. Shutdown (Normally closed, open to shutdown). To shutdown unit on normal or emergency stops. A "de-energized to shutdown" solenoid shall be coordinated with this contact for lock-out shutdown events.
2. Reset microprocessor initiated and latched shutdown status.
3. Raise Gate Servomotor Limit
4. Lower Gate Servomotor Limit
5. Start/Run
6. Raise Speed Reference (Speed Setter)
7. Lower Speed Reference (Speed Setter)
8. Starting Gate Servomotor Limit
9. Raise MW Reference (Power Setter)
10. Lower MW Reference (Power Setter)
11. Generator Breaker (closed when generator breaker closed)
12. Tie Breaker (closed when remote tie breaker closed)

3.7.4 Digital Control Outputs

1. Actuator Output
2. Relay Outputs

Example:

- Digital Control Alarm
- Overspeed Trip
- Digital Control Initiated Shutdown

3. Panel Meter Readout Analog Voltage Outputs

Example:

- Unit Speed
- Speed Reference
- Unit Generation MW Reference
- Gate Servomotor Limit
- Gate Servomotor Position

3.7.5 Auxiliary Equipment

Specifications should be provided for the following equipment:

1. Wicket Gate Servomotor Position Transducer and Limit Switches
2. Generator Brake-Air Low Pressure Switch
3. Emergency Stop Push-button
4. Pressure Transducers
5. Governor Oil Supply Pressure Switch
6. Shutdown Solenoid
7. Hydraulic Hand Control Transfer Switch
8. Electronic Hand Control Transfer Switch
9. Brake-Air Solenoid Valve

3.8 Governor Security and Fail Safe Requirements

Some general security and fail safe requirements are:

1. The electric-hydraulic transducer shall automatically close the gate servomotors using a mechanical spring or other means in the event of failure of the digital control and/or loss of

power supply voltage. The gates shall remain closed even if power is restored to the digital control. The digital control shall remain in this shutdown mode until an external reset contact is closed.

2. Altering of critical configuration parameters by unauthorized personnel using the keypad or other communication interface shall be prohibited by mechanical means inside the digital control enclosure and by a security password or access code.

3. Configuration parameters shall be saved in non-volatile permanent memory storage, preferably Electrically Erasable Programmable Read Only Memory (EEPROM), so that the configuration will be retained after a digital control power supply failure of any duration.

3.9 Power Supplies

Control power will be made available from the station battery.

The power supply system shall preferably include redundant converters (DC-DC) connected to the station battery source such that failure of any regulated output voltage shall cause instantaneous transfer to a redundant converter without affecting normal governor operation in any way.

3.10 Electromagnetic Interference Immunity

The governor shall be designed to be free from false operation or failure for all magnitudes of transients that can occur in the control circuitry and power supplies external to the governor actuator cubicle and speed signal generator (if used).

The governor system and/or individual components of the system shall generally be designed and tested to be immune from transients accordance with ANSI Standard C37.90.1.

3.11 Governor Actuator Cubicle and Digital Control Construction Cubicle

The following are some general specification guidelines for cabinet type governors.

3.11.1 Construction - General

Example:

The governing system shall be housed in enclosures, with access doors for adjustment and maintenance of the equipment. For a governing system with hydraulic actuation, the governor actuator cubicle shall contain all of the electric-hydraulic parts of the governor system. The digital control shall contain the electrical control circuits, display and keypad. The digital control shall be sealed to prevent entry of hydraulic oil and water (constructed to specifications)

and shall be shielded to prevent entry of Electromagnetic Interference (EMI). Grounding bar shall be provided.

The governor actuator cubicle shall be designed to enclose the equipment on all four sides and shall be manufactured from at least __ inch (__ mm) thick cold-rolled sheet steel. Each panel shall be not more than __ inches (___ mm) high, not including the actuator base. Suitable doors shall be provided to gain rapid and easy access to all equipment. The structure shall be the dead front-type, rigid, self-supporting and enclosed by a roof.

The governor actuator cubicle and digital control cubicle shall be painted as specified in the "_____" of Steel Structure Painting Council (SSPC), Steel Structure Painting Manual, Volume 2 (third edition), Painting System Guide No. ___. The color shall be ANSI _____.

Stiffeners shall be provided, where necessary, to achieve a high degree of rigidity in the completed panels.

3.11.2 Open-Access Governor Actuator Cubicle

Sample Text:

An open-access type governor actuator cubicle shall be acceptable provided that all sensitive and fragile components are suitably protected. The digital control enclosure shall be sealed to prevent entry of hydraulic oil and water (constructed to CEMA/NEMA TYPE ___ specifications) and shall be shielded to prevent entry of Electromagnetic Interference (EMI). A suitable panel can be supplied for mounting of the panel meter readouts, lamps, and control switches.

3.11.3 Test Facilities

Example:

The governor equipment shall be self-monitoring and self-diagnostic using the display and keypad mounted on the digital control.

3.11.4 Indicating Lamps

A schedule specifying the indicator lamps required shall be provided:

Example of indicators on an actuator cubicle:

Function	Engraving
Governor Oil Pressure Tank Level	
High	tank high level
Low	tank low level
Governor Oil Pumps	
Pump No. 1 on	
Pump No. 2 on	
Governor Low Sump Level	
Hydraulic Hand Control	
On	
Off	
Electronic Hand Control	
On	
Off	
Air Brakes	
Electrically Applied	
Mechanically Applies	
Digital Control Alarm	
Shutdown Solenoid Mechanically Latched	

The terminals for duplicate remote indicating lamps may also be specified.

3.11.5 Control Switches

A schedule of required control switches should be provided.

Example:

The Contractor shall provide two control switches on the front of the governor actuator cubicle. The control switches shall come with the appropriate contacts specified in Section ____ ELECTRICAL SPECIFICATIONS AND RATINGS.

Function/Position	Engraving
Hydraulic Hand Control Transfer Switch	HYDRAULIC HAND CONTROL
Hydraulic Hand Control Off	OFF
Hydraulic Hand Control On	ON
Electronic Hand Control Transfer Switch	HYDRAULIC HAND CONTROL
Electronic Hand Control Off	OFF
Electronic Hand Control On	ON

3.12 Hydraulic Pressure Supply System[4]

IEEE Standard 125 provides good specification guidelines for the following components of the hydraulic pressure supply system.

3.12.1 Pressure Pumps

See IEEE Standard 125.

3.12.2 Pressure Tank(s)

See IEEE Standard 125.

3.12.3 Sump Tank

See IEEE Standard 125.

3.12.4 Automatic Air Admission System

See IEEE Standard 125.

3.12.5 Electric Motors and Starters

See IEEE Standard 125.

3.12.6 Piping and Fittings

See IEEE Standard 125.

[4] IEEE Standard 125 *"IEEE Recommended Practice for Preparation of Equipment Specifications for Speed - Governing of Hydraulic Turbines Intended to Drive Electric Turbines"*

3.12.7 Hydraulic Pressure Supply System Pressure Gauge

See IEEE Standard 125.

3.13 Optional Equipment

3.13.1 Mechanical Overspeed Switch

One mechanically actuated speed switch, driven directly off the generator pilot exciter shaft, shall be supplied for the overspeed function. The mechanical speed switch shall be set as follows:

Overspeed ___% accelerating

3.13.2 Creep Detection

The unit creep detector shall not generate false alarms during interruptions of the DC control circuits.

3.14 Shop Assembly and Tests

3.14.1 Shop Assembly

Example:

The governor actuator cubicle and the digital control, piping, instruments, and wiring shall be erected in the shop to verify the design and assembly, and for the purpose of conducting shop tests.

3.14.2 Pressure Tests

The pressure valves and piping shall be subject to a hydrostatic test pressure of 1.5 times the maximum allowable working pressure for a period of 30 minutes. Any leaks or defects shall be repaired and re-tested until a 30 minute leak free period is obtained. Drain piping shall be tested at ___ psi (___ kPa).

3.14.3 Functional Tests

The ___ shall be functionally tested to demonstrate compliance with the Specifications to the satisfaction of the Contractor. Such tests shall simulate normal operating conditions as closely as possible.

3.14.4 Witnessing of Shop Assembly and Tests

The shop assembly and tests shall be witnessed by the Contractor or its representative. No equipment shall be shipped from the shop floor until it has been inspected and released or until written notice is received that inspection has been waived.

3.14.5 Field Acceptance or Owner Tests

The Contractor shall prove the on-line and off-line characteristics of the governor after installation.

C
HYDROMECHANICAL SUPPLIERS

List of Suppliers

The global marketplace for the supply of hydromechanical equipment is complex and ever-changing. Recommended sources of up to date information regarding the suppliers and goods and services connected with hydromechanical equipment include:

- *Hydro Review Industry Sourcebook* published yearly by HCI Publications, 410 Archibald Street, Kansas City, MO 64111-3046, USA.
- *International Water Power and Dam Construction* Yearbook published yearly by Wilmington Business Publishing, Wilmington House, Church Hill, Wilmington, Dartford, Kent DA2 7EF, UK.

Over time, with mergers and acquisitions in the industry, it has become, in some cases, difficult to identify the current "Original Equipment Manufacturer" (OEM) for a particular brand of turbine. The following list of turbine manufacturers has been prepared to assist with the identification process. The list is not exhaustive. Colloquial names have been used in lieu of formal company names for ease of identification.

Manufacturer	Associated Brand Names
American Hydro	
Andino	Noell
Ansaldo S. Giorgio	
ABB Alstom Power	Neyrpic English Electric GEC Alsthom Marine Industries Ltd.
BHIL	
CKD Blansko	
Fuiji	

Hydromechanical Suppliers

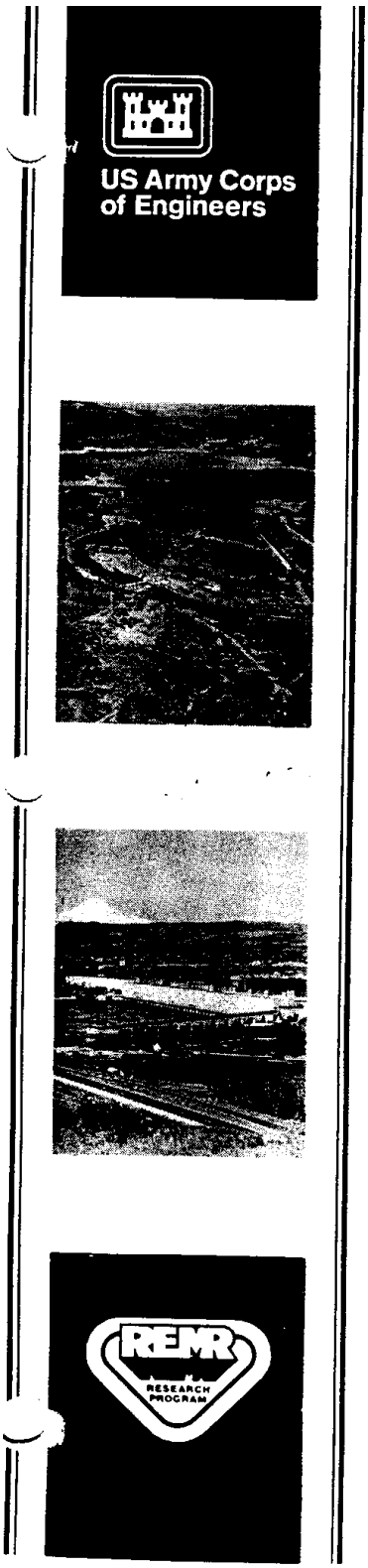
Manufacturer	Associated Brand Names
GE Hydro	Boving Dominion Engineering Works (DEW) KMW Kvaerner Nohab Tampela
Gilkes	
Harbin Electric Machinery Co.	
Hitachi	
IMPSA	Hugal AG
KTZ	
Litostroj	
LMZ	
Mitsubishi	
Newport News	
Toshiba	
VA Tech	VA Tech Voest MCE Voest-Alpine MCE Sulzer Hydro Escher Wyss VA Tech Hydro Vevey Baldwin-Lima-Hamilton Co. I.P. Morris Pelton VA Tech Bouvier
Voith-Siemens Hydro	Voith Allis Chalmers Canadian Allis Chalmers Riva Hydroart S Morgan Smith

D
REMR CONDITION ASSESSMENT PROCEDURES

This appendix includes reproductions of the appropriate sections for equipment covered in this volume of the US Army Corps of Engineers' Condition Rating Procedures/Condition Indicator for Hydropower Equipment. The document was produced by the USACE as part of the repair, Evaluation, Maintenance and Rehabilitation (REMR) Research Program.

As discussed in Section 4.4.1 the condition rating procedures are provided as an example of a condition rating procedure. The USACE intends to review the procedures commencing in 2000.

Our thanks to Messrs. Jim Norlin, Paul Willis and Craig Chapman of the USACE in ensuring that the REMR procedures are reproduced here.



REPAIR, EVALUATION, MAINTENANCE, AND REHABILITATION RESEARCH PROGRAM

REMR MANAGEMENT SYSTEMS–HYDROPOWER FACILITIES

CONDITION RATING PROCEDURES/ CONDITION INDICATOR FOR HYDROPOWER EQUIPMENT

by
Department of the Army
Hydroelectric Design Center
North Pacific Division
Corps of Engineers
PO Box 2870
Portland, Oregon 97208-2870

March 1993

Working Document

Approved For Public Release; Distribution Unlimited

Prepared for DEPARTMENT OF THE ARMY
US Army Corps of Engineers
Washington, DC 20314-1000
Under Civil Works Research Work Unit 32672

The following two letters used as part of the number designating technical reports of research published under the Repair, Evaluation, Maintenance, and Rehabilitation (REMR) Research Program identify the problem area under which the report was prepared:

	Problem Area		Problem Area
CS	Concrete and Steel Structures	EM	Electrical and Mechanical
GT	Geotechnical	EI	Environmental
HY	Hydraulics	OM	Operations Management
CO	Coastal		

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COVER PHOTOS:

TOP - Lost Creek Flood Control/Hydropower Project, Rogue River, Oregon.

BOTTOM - The Dalles Navigation/Hydropower Project, Columbia River, Oregon.

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Washington Headquarters Services, Directorate for Information Operations and Reports, 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302, and to the Office of Management and Budget, Paperwork Reduction Project (0704-0188), Washington, DC 20503.

1. AGENCY USE ONLY (Leave Blank)	2. REPORT DATE	3. REPORT TYPE AND DATES COVERED
	March 1993	Working Document

4. TITLE AND SUBTITLE

Condition Rating Procedures/Condition Indicator for Hydropower Equipment

5. FUNDING NUMBERS

Civil Works Research
Work Unit 32672

6. AUTHOR(S)

James A. Norlin, Darilynne Allen, Donald J. Campbell, Marc Frey, Jerry Joy, Mark Pierce, David C. Raisanen, Richard Vaughn, and Glenn Woodward

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)

US Army Corps of Engineers
North Pacific Division
Hydroelectric Design Center (CENPD-PE-HD)
PO Box 2870
Portland, OR 97208-2870

8. PERFORMING ORGANIZATION REPORT NUMBER

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)

US Army Construction Engineering Research Laboratories (USACERL)
PO Box 9005
Champaign, IL 61826-9005

10. SPONSORING/MONITORING AGENCY REPORT NUMBER

11. SUPPLEMENTARY NOTES

12a. DISTRIBUTION/AVAILABILITY STATEMENT

Approved for public release; distribution unlimited.

12b. DISTRIBUTION CODE

13. ABSTRACT (Maximum 200 words)

The Hydropower Condition Indicator Manual is a maintenance management tool for condition assessment and evaluation of electrical and mechanical equipment in hydroelectric powerhouses.

Data on various pieces of hydropower equipment is gathered by field inspection and testing. Uniform procedures are applied to evaluate the data and assign a Condition Index (CI) to the equipment. The CI indicates the condition of the equipment. The CI thus affords a means for the uniform and quantitative comparison of the condition of equipment to that in another.

The collected data will eventually yield curves documenting the deterioration of equipment based upon age and usage. Such curves can be used to predict future condition so that maintenance managers can optimally prioritize and budget maintenance and rehabilitation money.

14. SUBJECT TERMS

hydropower
condition
maintenance management
testing
evaluation

15. NUMBER OF PAGES

422

16. PRICE CODE

17. SECURITY CLASSIFICATION OF REPORT	18. SECURITY CLASSIFICATION OF THIS PAGE	19. SECURITY CLASSIFICATION OF ABSTRACT	20. LIMITATION OF ABSTRACT
Unclassified	Unclassified	Unclassified	SAR

NSN 7540-01-280-5500

Standard Form 298 (Rev. 2-89)
Prescribed by ANSI Std. 239-18
298-102

PREFACE

The study reported herein was authorized by Headquarters, US Army Corps of Engineers (HQUSACE), as part of the Operations Management problem area of the Repair, Evaluation, Maintenance, and Rehabilitation (REMR) Research Program. The work was performed under Civil Works Research Work Unit 32672, "Development of Uniform Evaluation Procedures and Condition Index for Civil Works Structures," for which Dr. Anthony M. Kao (CECER-FMM) is the Principal Investigator. Mr. James A. Norlin **(CENPD-PE-HD),** Hydroelectric Design Center (HDC). is the Principal Investigator and Mr. Craig Chapman (CECW-OM) is the Technical Monitor for this study.

Mr. Jesse A. Pfeiffer, Jr. (CERD-C) is the REMR Coordinator at the Directorate of Research and Development, HQUSACE. Mr. James E. Crews (CECW-O) and Dr. Tony Liu (CECW-ED) serve as the REMR Overview Committee; Mr. William F. McCleese (CEWES-SC-A), US Army Engineer Waterways Experiment Station (WES), is the REMR Program Manager. Dr. Anthony M. Kao (CECER-FMM) is the Problem Area Leader for the Operations Management problem area.

This work was conducted by the Hydroelectric Design Center under the general supervision of Glenn R. Meloy, Chief of CENPD-PE-HD.

Acknowledgement is given to the Field Review Group members and to the numerous individuals at many of the Corps' operating projects that have reviewed, tested and commented on the procedures outlined in this manual. Their input has been invaluable in the acceptance and useability of this document.

COL Daniel Waldo, Jr., is Commander and Director of USACERL, and Dr. L.R. Shaffer is Technical Director.

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PART I: INTRODUCTION

1-1. The Corps of Engineers owns and operates 76 hydroelectric powerhouses located throughout the United States. These powerhouses have a combined total capacity of nearly 21,000 megawatts, making the Corps the largest single operator of hydroelectric facilities in the United States.

The Corps' system of hydropower projects is unique and significantly different than other large producers of hydropower in several ways. We do not supply power to a single system, but rather to many large and small power distribution systems throughout the country. We are involved only with hydropower and power production, and have no direct involvement in power distribution or sales. Our funding for repair and replacement of equipment is appropriated by congress, and not derived from power sales.

Planning for major repairs or replacement of hydropower equipment presents some unique difficulties to the Corps. Funds are provided as a part of the overall Operation and Maintenance budget for the Corps. The funding is thus intermingled with funds for dredging, navigation, flood control, recreation and most other aspects of the Corps' involvement with civil works activities. The funding requirements for the O&M of hydropower facilities is a relatively small portion (5-6%) of the overall Corps of Engineers O&M budget.

The cost of routine operation and maintenance activities can be programmed relatively easily based upon historical efforts. The non-routine effort is much more difficult to forecast. This program is a key step in the development of a reliability centered maintenance program. This program will provide comprehensive projections of the need for and benefits derived from specific, non-routine maintenance work.

Concept

1-2. The Hydropower Equipment Condition Indicators Program is being developed at the direction of HQUSACE as a part of the Operations Management Problem Area of the Repair, Evaluation, Maintenance and Rehabilitation Research Program (REMR). REMR Management Systems are designed to be decision support tools for determining when, where, and how to effectively allocate maintenance and rehabilitation dollars for Civil Works facilities. These systems are being developed to provide:

a. Objective condition assessment procedures.

b. Means for comparing the condition of facilities and tracking change over time.

c. Procedures for life-cycle cost analysis of different maintenance policies and rehabilitation alternatives.

d. Computer software for storing and organizing data, performing calculations, and producing a variety of reports.

There are many independent factors that must be considered as key elements of an overall maintenance management program. The items in the following list are all pertinent, but the list is not necessarily all inclusive.

1 - Policy / Planning / Mission

2 - Condition / Function / History/Performance

3 - Importance of facility

4 - Economic Analysis

5 - Risk / Consequences of failure

6 - Repair lead time

7 - Budget / Current - Future

8 - User Cost

9 - Return on Investment

10 - Resource availability

11 - Future performance

One of the primary goals of the REMR Operations Management System is to take all of these factors and place them into a single, large computer program that will be used as a management tool. It is anticipated that the final product could take as much as 10-20 years to fully develop, test, refine and implement. A program of this nature must be developed one step at a time.

The chosen starting place is the technical area. This is item 2 on the list above. Factors that can be considered relevant to the Condition / Function / History/ Performance of a piece of hydropower equipment are as follows:

1 - Current Condition

2 - Current Performance

3 - Past Condition and Performance (History)

4 - Future Condition and Performance (Estimate or prediction)

5 - Trends

6 - Equal comparison of facilities condition / performance

7 - Definition of required function

The items on this list can be separated into two general categories, equipment condition and performance of function.

The current program is limited to looking at the category of equipment condition only. The performance of function factors will be considered at a later time.

The initial step in determining the current condition of a piece of equipment is to establish a standard definition of condition. This has already been established as the REMR Condition Index scale. This scale is numerically based, extending from 0 to 100, without units. REMR Technical Note OM-CI-2 which further defines and explains the condition index scale is included in this report as Appendix A.

The second step is to develop a standard method of measurement of condition. A standard indicator is something that is specifically definable, and repeatable. An example of definable and repeatable is the measurement of "volts". There is a specific definition for "volts", and calibrated test instruments for measuring voltage. As a result, there is no confusion or misunderstanding when someone says that a particular piece of equipment is designed to operate at 110 volts AC, for example. The indicators and methods used to define the condition of equipment should strive to be equally as well defined and repeatable. The point being that when two project engineers on opposite sides of the country each say their turbines have "bad cavitation damage", the actual extent of damage to each turbine is comparable.

Generally speaking, Condition Indicators are either test results from standard tests, or visual or other non-destructive examinations that give an indication of the current condition of a piece of equipment. Factors such as usage, history of maintenance, availability of parts and economic factors are not to be considered when defining current condition. These are important elements, but they will be considered elsewhere in the overall REMR Operations Management System.

The Condition Index, by definition, is a snapshot look at the absolute condition of a facility or piece of equipment. Time, age and money related factors are not included in the development of this index. It is a standardized evaluation of the condition of the equipment based strictly upon test results and inspection by visual or other means. The condition index algorithm should allow for the additional *condition information* that is available from a detailed inspection if the equipment is partially or totally dismantled for other reasons, but should not require this type of inspection.

Just as a chain is only as strong as the weakest link, the current condition of most pieces of hydropower equipment is only as good as the poorest indicator. This method of overall evaluation allows for an easy method of determining the work necessary to improve the condition and the extent of overall improvement. An exception to this general rule is made when several different tests or inspections are used for evaluating the same thing. The best example of this is the myriad of tests used to evaluate the condition of generator stator winding insulation.

Snapshots of the equipment condition can be taken at regular or irregular intervals. Regular intervals would normally include two separate condition evaluations at each major maintenance interval (for example -quadrennial). The initial evaluation would reflect the condition of the equipment as it was removed from service for maintenance. The second evaluation should reflect the improvement in condition as a result of maintenance procedures. For example, during a turbine overhaul, normal maintenance procedures call for weld repair of areas damaged by cavitation. The two evaluations of condition should accurately reflect the improvement in the condition of the turbine as a result of these weld repairs.

Other measurements that will affect how well equipment can be expected to survive, such as hours of usage, severity of usage and levels of routine maintenance will be used to predict the future rate of condition index deterioration. This will be developed during a later phase of the overall REMR Operations Management System.

Limitations

1-3. Condition indices are a tool to help estimate the remaining service life of equipment. Service life, however, is not necessarily the same as useful life. Powerhouse Automation Systems, for example, are most often replaced for reasons other than condition.

Example

1-4. The example used to demonstrate how Conditions Indicators for mechanical and electrical equipment are used, is something that everyone is familiar with, an automobile. The condition of a specific automobile is something that can be determined by an automotive

diagnostic center. Through testing and inspection, they can evaluate the condition of the vehicle and provide a detailed listing of the items that are not properly operational.

However, the diagnostic center cannot provide all of the information that is necessary to determine the extent of repairs that should be performed, or if the vehicle should be replaced. Economics obviously will play a major part of this decision. The functionality of the vehicle for the purpose it is needed also plays a part. You wouldn't buy a two seat sports car if you need to transport 4 people and their luggage on a regular basis. Finally, the diagnostic center cannot predict how long it will be before the vehicle sustains a major failure.

We need to eliminate factors that are not relevant to condition before proceeding to those factors that are relevant. The age of the automobile is the first factor to eliminate. Assume that the theoretical design life for an automobile is 15 years. Many cars will last well past that age, but a great number will see a wrecking yard as a result of mechanical failure much sooner. However, the condition of a vehicle is not dependant upon its age. Consider all of the collector cars that are in better condition now than they were when they were new. Likewise, consider the new car that has a transmission failure in the first 10 miles because a mechanic forgot to put oil in the gearbox.

It is therefore easy to eliminate age as being irrelevant to condition.

The next factor to eliminate is usage. The diagnostic center cannot tell what use or abuse a car has seen. Three similar cars, each with 99,000 miles on the odometer may each have seen dramatically different service. One may be all stop and go city miles, another highway miles and the third may actually have 299,000 miles on the odometer.

Thus, we also eliminate operational history or usage.

Maintenance history can also be eliminated. The diagnostic center does not have access to the maintenance records, nor are they familiar with the skills of the mechanic. However, they can get a good indication of the level of maintenance from visual inspection. Rusty body panels along with tape and bailing wire repairs are very obvious. This would indicate a car in much poorer condition than another vehicle with a freshly waxed paint job and all bolts where they belong.

Maintenance history is eliminated, but a thorough visual inspection is included.

The diagnostic center, in addition to completing a thorough visual examination, will perform many different types of tests. These tests will check out the various electrical and mechanical systems of the vehicle. A compression test combined with a leak-down test and an examination of the lubricating oil will give a relatively good indication of the mechanical condition of the engine. These tests can be run on virtually all cars. Tests on other systems may vary depending upon the vehicle. For example consider the fuel supply system. There are carburetors, mechanical fuel injection systems, electronic fuel injection systems and turbocharged versions of each. They all perform the same function in a different manner. Certain tests, such as an exhaust gas analysis, can be used to get a very basic indication of the condition of any of these

systems. Other, more specialized tests are relevant to only one type of system. However, these tests can give a better indication of condition.

We have included only these basic tests for most of the items of hydropower equipment. In many cases, more detailed tests could be run, but the value of performing them on a routine basis is questionable.

Categories of Equipment

1-5 The following categories of hydropower equipment are included as part of this program:

ELECTRICAL

Hydrogenerator Stators

Excitation Systems

Circuit Breakers

Main Power Transformers

Powerhouse Automation Systems

MECHANICAL

Turbines

Thrust Bearings

Intake Valves

Governor System

Cranes & Wire Rope Gate Hoists

Hydraulic Actuator Systems

STRUCTURAL

Emergency Closure Gates

Power Penstocks

PART VII: TURBINES

Program, Format and Method

Explanation of Program

7-1. The overall turbine condition number is a number between 0 and 100 which will be used to define the present condition of a turbine. The number will be used in the REMR Condition Index Scale which is shown below.

The overall turbine condition number is calculated from eight condition index numbers. These eight condition numbers are determined from various tests and inspections done on a turbine unit.

The eight condition indices selected are: Component breakage/repair/ wear, oil loss, blade/vane cracking, cavitation damage, shaft runout, stick

Condition Index Scale

Value		Condition Description
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate
25-39	Poor	Serious deterioration in at least some portions of
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Figure 7-1

slip, field performance tests and surface condition. These eight were selected because absolute numbers can be obtained and subjective interpretation during the test or inspection can be minimized. Also, there was some information in the Corps and outside the Corps on what were acceptable and not acceptable values for most of these indicators. Lastly, all the tests associated with these conditions are fairly simple to perform.

Explanation of Format

7-2. The condition indices all have a similar format. The first sheet is an explanation sheet which describes the test or inspection, gives instructions on how to perform the test or inspection, explains how to fill out the data-evaluation sheet and gives the recommended frequency of performing the test or inspection. Next, there are tables or figures which are used to determine a condition number based on the results of an inspection or test. Following this is the data-evaluation sheet where information is recorded and calculations made. Also attached is a sample Data Evaluation Sheet. The last sheets are specific inspection sheets used for mapping damage or defects. Not all indicators have these inspection sheets.

Explanation of Method

7-3. A condition number between 0 and 100 is determined for each condition index based on the results of tests and inspections. Each explanation sheet gives instructions on testing and evaluation. The overall condition number for the turbine is the lowest value of any of the condition index values.

Overall Turbine Condition

Introduction

7-4. The overall turbine condition is calculated using eight condition indicators: component breakage/repair/wear, oil loss, blade cracks, cavitation shaft runout, stick slip, field performance tests and surface condition. Each indicator is assigned a condition number. The condition numbers are calculated based on the results of various tests and inspections which are discussed later.

Filling Out Data Evaluation Sheet

7-5. Column 1 lists the eight condition indicators which are used for turbine evaluation. Others may be added in the future. In column 2, fill in the date the test or inspection was made. In column 3, insert any notes or remarks about the condition index. For instance, if the condition number for a condition index was low, put in the reason for it being low. In column 4 put the condition number for the particular condition indicator. This number is obtained from the box in the lower right corner of the Data Evaluation Sheet for each individual indicator.

The overall turbine condition number is the lowest of the individual condition indicator numbers. This number is placed in the box in the lower right corner of the Overall Turbine Condition Data Evaluation Sheet. A sample of this form is shown on page 4. Information to be completed by the field is shown in script text.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Turbine Condition

Project: *Old Hydro Plant* Unit No._____

Type of Turbine: *Francis*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of inspection or test	Remarks	Condition No. 0-100
Component Damage	*6/27/90*	*Twisted wicket gate stems, excessive gate leakage, damaged wear rings, cracked welds in head cover*	40
Oil Loss	*6/27/90*	*Minimal leakage from turbine guide bearing*	*90*
Blade Cracks	*6/27/90*	*Numerous small cracks on trailing edge of buckets*	*60*
Cavitation	*6/27/90*	*Light cavitation on runners, severe cavitation on discharge ring*	*40*
Shaft Runout	*6/27/90*	*High runout near turbine guide bearing*	*25*
Stick Slip			
Field Performance Tests			
Surface Condition			
		Overall Turbine Condition Index Rating	*25*

Component Damage

Introduction

7-6. This evaluation is used to determine the condition of the turbine based on breakage, repair and wear of components. Cavitation and runner blade cracks which are covered in other indicators should not be evaluated here. Condition numbers will be assigned to various components of the turbine based on the damaged and repair state, and another number assigned based on the wear state.

Instructions for Evaluation

7-7. The major turbine components should be visually examined for condition, wear, breakage and repair. These include the runner, head cover, wicket gates and mechanism, servomotors and turbine shaft. This inspection does not involve dismantling components. Cavitation and runner blade cracks are not to be included in this evaluation.

Information is recorded on the Data Evaluation Sheet for various components of the turbine.

Filling Out Data-Evaluation Sheet

7-8. Column 1 lists the major component categories. In column 2, fill in the date on which that particular component was inspected. In column 3, put in notes on the condition of components with respect to any broken parts, temporary repair or abnormal wear.

A condition number between 0 and 100 is assigned to each component depending on its breakage-repair state, and another condition number will be assigned based on its wear state. The condition numbers are obtained from Tables la and lb. The condition number for each component with respect to breakage and repair is placed in column 4. The condition number for each component with respect to wear is placed in column 5.

The overall component damage condition number is the lowest condition number from column 4 or 5 for any of the components. This number is placed in the box in the lower right corner of the Data Evaluation Sheet.

A sample Component Damage Data Evaluation Sheet is shown on page D-25. Information to be completed by the field is shown in script text.

Frequency of Inspection

7-9. Each time the unit is shut down for major, routine overhaul work, or the unit is taken off line because of a turbine related problem, an inspection should be made. A second evaluation should be made after any repairs are completed to document the condition improvements made as a result of the repairs.

Table 7-1a

Condition Numbers Based on Component Breakage-Repair

No broken or repaired components.	100
Component has permanent repair that is functioning adequately	80
Component has temporary repair that is functioning adequately	60
Component has repair and is functioning but function is not adequate.	40
Turbine is operational, but component broken and not functioning. (example: blocked kaplan blades)	20
Turbine is not operational due to component breakage	0

Table 7-1b

Condition Numbers Based on Component Wear

Components in new or almost new condition	100
Components exhibiting minor signs of wear and deterioration	90
Components exhibiting moderate signs of wear and deterioration.	60
Components exhibiting major signs of wear and deterioration.	30
Turbine is operational. Component is not functioning due to deterioration and/or wear.	20
Turbine is not operational due to component deterioration and/or wear.	0

Note: Exclude cavitation and runner cracks.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Breakage Repair/Wear

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of inspection or test	Remarks	Condition No. 0-100 based and Breakage and Repair	Condition No. 0-100 based on Wear
Runner	*7/1/90*	*Previous weld repairs*	*70*	*100*
Head Cover	*7/1/90*	*3 cracked welds on stiffeners*	*80*	*100*
Wicket Gates	*7/1/90*	*3 twisted wicket gate stems, excessive leakage, wire drawing on 4 gates*	*100*	*40*
Wicket Gate Mechanism	*7/1/90*	*4 gate links replaced, operating ring out of round, bushings showing moderate*	*80*	*60*
Servomotors	*7/1/90*	*Satisfactory*	*100*	*100*
Shaft	*7/1/90*	*Satisfactory*	*100*	*100*

Overall Component Damage Condition Index Rating: 40

Oil Loss

Introduction

7-10. This evaluation is used to determine the condition of turbine oil loss through leakage based on the amount of oil added to the turbine per year and the severity of the problem caused by the leakage.

A condition number is assigned based on the quantity of make-up oil added to the turbine, and the type of the drainage system that the leaked oil enters. Oil leaking into the river or the powerhouse drainage system is a more severe problem than oil leaking into an oil sump.

Instructions for Evaluation

7-11. Detailed records of oil usage should be maintained. These records should include the date that oil was added to the unit, hours of turbine operation between each addition of oil, and the quantity of oil added.

The amount of oil added per year is recorded on the Data Evaluation Sheet. This should not include oil changes but only make-up oil. If records are for a period of less than one year, the results should be converted to a yearly basis.

Attach a copy of oil usage records to the Data Evaluation Sheet for the period evaluated.

Filling Out Data-Evaluation Sheet

7-12. Column 1 lists the various turbine oil systems. Fill in the line pertaining to the oil system that you are evaluating, i.e. turbine hub, guide bearing etc. All systems may not be relevant for all turbines. Fill in the oil added to that system for a certain period, converted to a yearly basis in column 2. Record the location of oil leakage if it is known in column 3. Column 4 may be used for notes and records about the oil addition or leak.

The relative oil usage is calculated by taking the total gallons of oil added per year from all the turbine systems, divided by the square of the runner diameter in inches.

The oil usage condition number, between 0 and 100, for the turbine is determined from Table 7-2A for Kaplan units and Table 7-2B for Francis units. It is dependent on the relative oil usage number and the destination of the oil leaked. If any of the leakage reaches the river, or the powerhouse drainage system, use the Environmental Hazard column of condition numbers. If none of the leakage enters the river or the powerhouse drainage system, use the Nuisance column of condition numbers. Fill in the oil usage condition number in the box in the lower right corner of the Data Evaluation Sheet.

A sample Oil Loss Data Evaluation Sheet is shown on page D-29. Information to be completed by the field is shown in script text.

Frequency of Evaluation

7-13. In general, oil usage should be evaluated at least once a year. If usage appears heavy or leaks are observed, the frequency of evaluation should be increased.

Table 7-2A

Condition Numbers Based on Relative Oil Usage (Kaplan Units)

Relative Oil Usage	Condition Number	
	Environmental	Nuisance
0 - 0.0022	80	100
0.0022 - 0.0044	70	100
0.0044 - 0.0067	60	100
0.0067 - 0.0089	50	90
0.0089 - 0.0111	40	80
0.0111 - 0.0133	30	70
0.0133 - 0.0156	20	60
0.0156 - 0.0178	10	50
0.0178 - 0.0200	10	40
0.0200 - 0.0222	10	30
>0.0222	10	20

If the unit is shut down due to oil leakage to the river, the Condition Number is 0.

$$\text{Relative oil use} = \frac{\text{Gallons of Oil Added per Year}}{(\text{Runner Dia. in Inches})^2}$$

Table 7-2B

Condition Numbers Based on Relative Oil Usage (Francis Units)

Relative Oil Usage	Condition Number	
	Environmental	Nuisance
0 - 0.0007	80	100
0.0007 - 0.0015	70	100
0.0015 - 0.0022	60	100
0.0022 - 0.0030	50	90
0.0030 - 0.0037	40	80
0.0037 - 0.0044	30	70
0.0044 - 0.0052	20	60
0.0052 - 0.0059	10	50
0.0059 - 0.0067	10	40
0.0067 - 0.0074	10	30
>0.0074	10	20

If the unit is shut down due to oil leakage to the river, the Condition Number is 0.

$$\text{Relative oil use} = \frac{\text{Gallons of Oil Added per Year}}{(\text{Runner Dia. in Inches})^2}$$

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Oil Usage

Project: *Old Hydro Plant* Unit No. 1

Runner Diameter

150 inches

Type of Turbine: *Francis*

Prepared by: *I.N. Spector* Date: *7/3/90*

Oil System	Oil Addition (Gal/Year)	Location of Leakage (if Known)	Remarks
Intermediate Turbine Guide Bearing (If applicable)			
Lower Turbine Guide Bearing	*60*	*Lower Seal*	
Gate Servomotor(s)	*20*		*Minor Leakage noted*
Blade Servomotor Kaplan Hub (if applicable)	*N/A* *N/A*		
Total Leakage (Gal/Year)	*80*		*.0036* *90*

Note: Attach oil records

Relative Oil Usage = Gal/Yr/Runner Dia.^{2}

Oil Usage Condition Index Rating

Blade Cracks

Introduction.

7-14. This inspection is used to determine the condition of turbine blade cracking using visual detection methods. A condition number is assigned to a crack based on its length and location.

Instructions for Inspection

7-15. Each blade of the runner should be visually examined on both the high pressure and low pressure side. Each crack that is found is given an identifying number and the location is mapped on the blade crack inspection sheets. (Inspection sheets TU-1-FRM.PM4 PAGES 5 and 6 for Kaplan or fixed blade units and PAGE 7 for Francis units)

On the Data Evaluation Sheet, the length of the crack and its location or "zone" is recorded. Also indicate on the Data Evaluation Sheet any weld repairs made immediately prior to this inspection.

Filling Out Data-Evaluation Sheet

7-16. In column 1, fill in the blade number. All blades should be numbered. In column 2, fill in the crack number. This should correspond with the number used on the inspection sheets. There should be one line for each crack. In column 3, record the crack length in inches. In column 4, record the zone in which the crack was found. The zone is determined from Figure 1 for Kaplan or fixed blade units and from Figure 2 for Francis units. Column 5 may be used for notes and remarks about the inspection including crack depth, width or welding information.

A condition number between 0 and 100 is assigned to each blade depending on crack length and zone location. The condition number depends on the zone, the relative crack length which is calculated by dividing the actual crack length by the runner diameter in inches. Knowing the relative crack length and the zone where the crack is located, the condition number can be determined from tables 3 and 4.

The condition number for each crack is placed in column 6. The overall turbine blade crack condition number is the lowest condition number in column 6 and this number is placed in the box in the lower right corner of the Data Evaluation Sheet. A sample of this for is shown on page D-33. Information to be completed by the field is shown in script text.

Frequency of Inspection

7-17. Each time the unit is unwatered an inspection should be made. The frequency of inspection should be based upon the number of cracks detected.

Table 7-3

Zones and Condition Numbers for Kaplan or Fixed Blade Units

Relative Crack Length	Condition Numbers Zone 1	Zone 2	Zone 3
Greater than 0.03	10	30	30
0.01 to 0.03	20	40	45
0.001 to 0.01	30	50	60
Less than 0.001	40	60	80

Calculation of Relative Crack Length

7-18. The relative crack length is calculated by taking the actual crack length in inches and dividing by the runner diameter in inches.

$$\frac{\text{Crack Length (in.)}}{\text{Runner Dia. (in.)}}$$

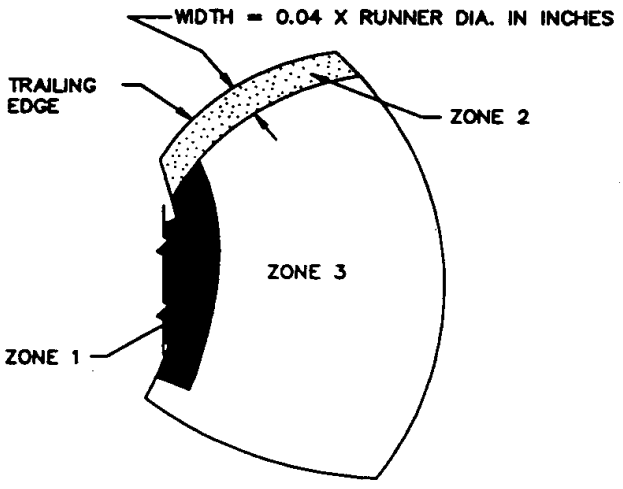


Figure 7-1 - Blade Zones

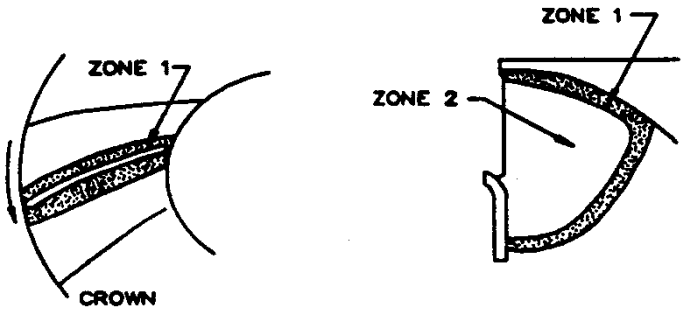
Table 7-4

Zones and Condition Numbers for Francis Units

	Condition Numbers	
	Zone	
Relative Crack Length	1	2
Greater than 0.01	10	40
0.007 to 0.01	10	50
0.003 to 0.007	20	60
Less than 0.003	30	70

Calculation of Relative Crack Length

7-19. The relative crack length is calculated by taking the actual crack length in inches and dividing by the runner diameter in inches.



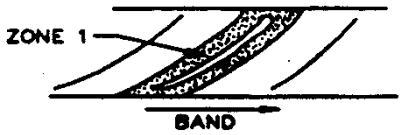


Figure 7-2 - Bucket Zones

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Blade Cracks

Project: *Old Hydro Plant* Unit No. *1*

Runner Diameter

150 inches

Type of Turbine: *Francis*

Prepared by: *I.N. Spector* Date: *7/3/90*

Blade Number	Crack Number	Length of Crack in Inches	Zone	Remarks	Condition Number 0-100
3	*1*	*½*	*2*		*60*
7	*1*	*¼*	*2*		*70*
7	*2*	*½*	*2*		*70*
15	*1*	*½*	*2*		*60*
15	*2*	*¼*	*2*		*70*
15	*3*	*½*	*2*		*60*
16	*1*	*¼*	*2*		*70*
				Overall Blade Crack Condition Index Rating	*60*

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
High Pressure Side of Kaplan or Fixed Blade

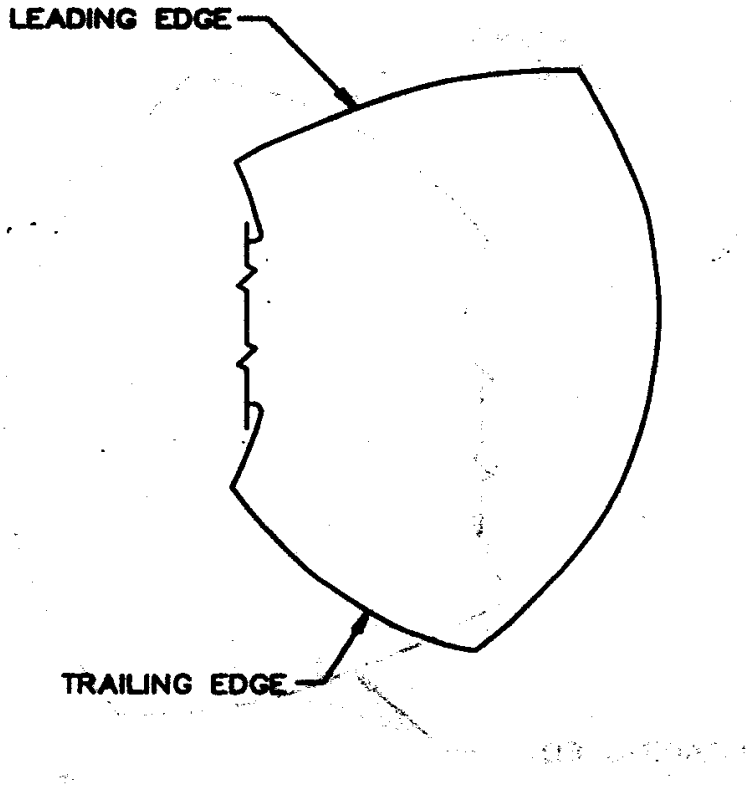
Blade Number

_____

Project: _____ Unit No._____

Type of Turbine: _____

Prepared by: _____ Date:_____



Identify location and length of cracks.
Make one sheet for each blade.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Low Pressure Side of Kaplan or Fixed Blade

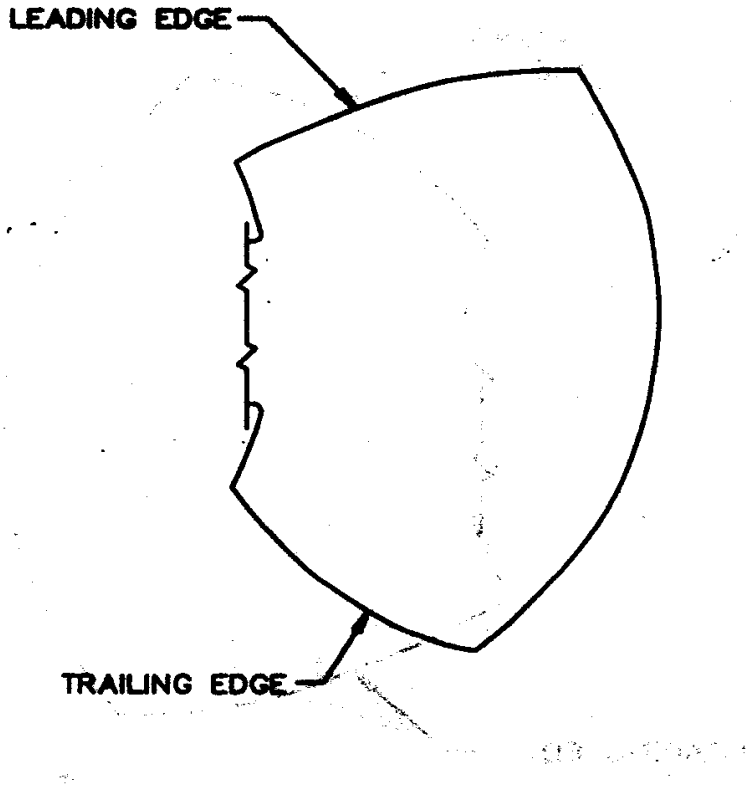
Project: _____ Unit No._____

Blade Number

Type of Turbine: _____

_____

Prepared by: _____ Date:_____



Identify location and length of cracks.
Make one sheet for each blade.

REMR Hydropower Condition Indicator Program

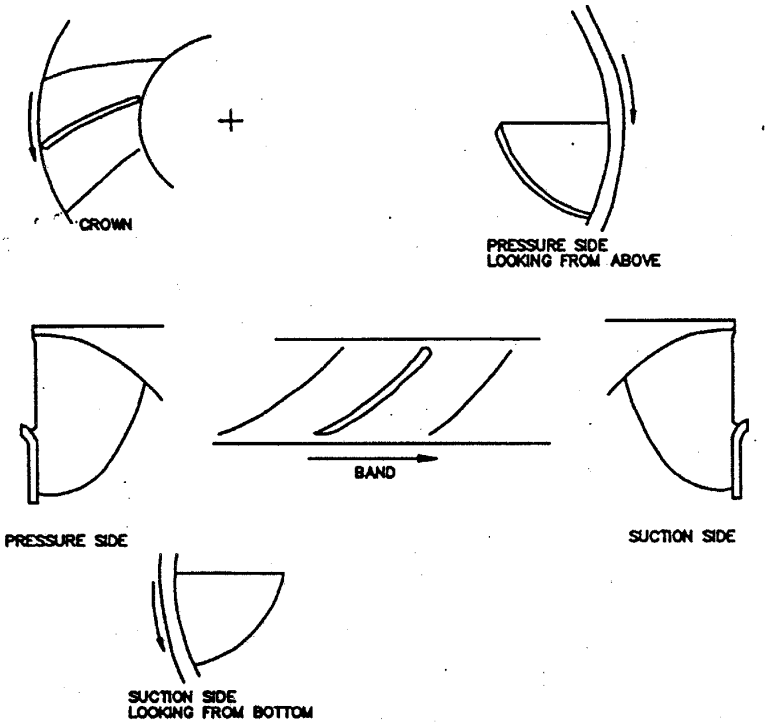
Turbine Blade Crack Inspection Sheet
Francis Runner

Project: *Old Hydro Plant* Unit No._____

Bucket Number
15

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*



Identify location and length of cracks.
Make one sheet for each blade.

Cavitation

Introduction

7-20. This inspection is used to determine the condition of turbine cavitation on the runner and water passages. A condition number is assigned to turbine components based on weight of material removed by cavitation or the depth of pitting.

Instructions for Inspection

7-21. Cavitation damage on the runner blades, crown, band, discharge ring, draft tube liner, wicket gates and head cover should be measured and mapped. Inspection form TU-1-FRM.PM4, PAGES 9 through 16 give details of the inspections.

Figures 4 and 5 show areas where cavitation is typically found on Kaplan and Francis turbines respectively. The weight of material removed and the maximum pitting depth taken from inspection forms are recorded on the Data Evaluation Sheet.

Filling Out Data Evaluation Sheet

7-22. Column 1 lists the locations where cavitation is measured. Fill in the weight of material removed from the particular component, taken from Inspection Sheet 2, in column 2. For the blades, this should be the total for all blades from both the high pressure and low pressure sides. Total the weights for the runner components in box A and total the weights for discharge ring and draft tube liner in box B. Fill in the maximum pitting depth for a particular component in column 3. This is obtained from inspection sheet number 3. Column 4 may be used for notes and remarks about the cavitation damage.

Divide the total in column 2, box A and B by the hours of operation since the last cavitation repair was done on that unit, and place the result in column 5.

A condition number between 0 and 100 is assigned to the runner and the discharge ring/draft tube liner based on the pounds of material removed by cavitation per hour of operation. These condition numbers are found from Figures 3A through 3F. Pitting depth and Table 5 are used to determine the condition number for the wicket gates and head cover. The condition number for each component is placed in column 6.

The overall cavitation condition number is the lowest condition number of any of the components. Ibis number is placed in the box in the lower right corner of the Data Evaluation Sheet. A sample of this form is shown on page 7-33. Information to be completed by the field is shown in script text.

Frequency of Inspection

7-23. Inspection frequency should not exceed once every four years. The frequency should be increased if the unit shows excessive cavitation. New units should be inspected on an annual basis for the first five years.

Note:

This cavitation evaluation has been prepared based upon information developed by EPRI, the Electric Power Research Institute.

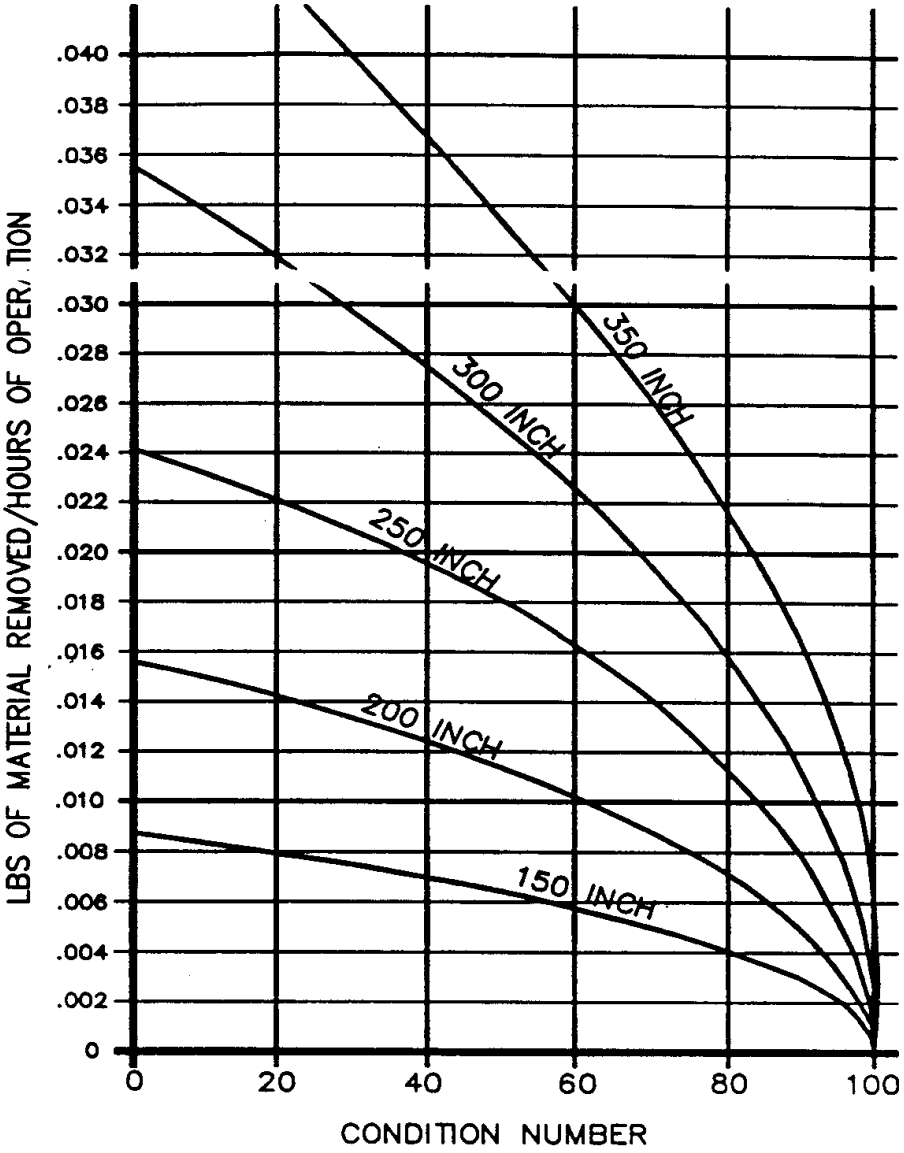


Figure 7-3A

Cavitation Condition Numbers for Large Kaplan
and Propeller Turbines
Runner Cavitation

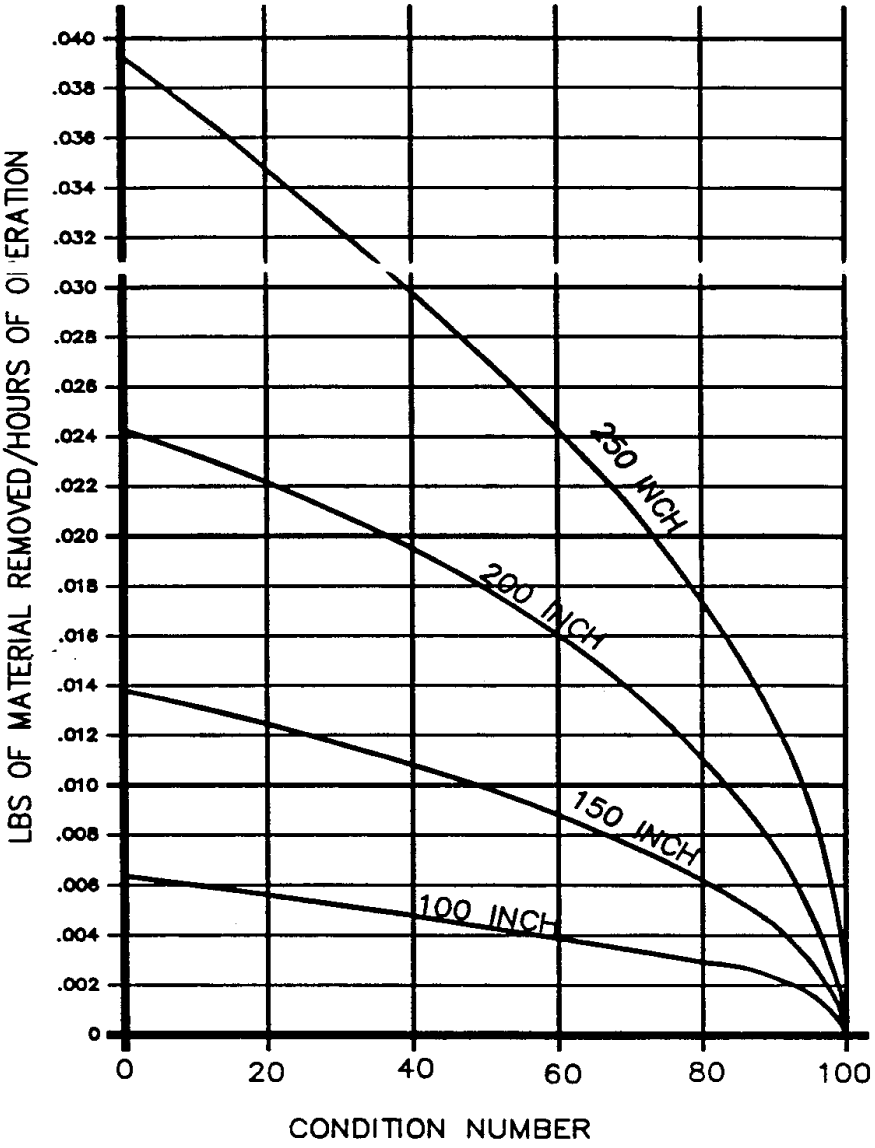


Figure 7-3B

Cavitation Condition Numbers for Large Francis Turbines
Runner Cavitation

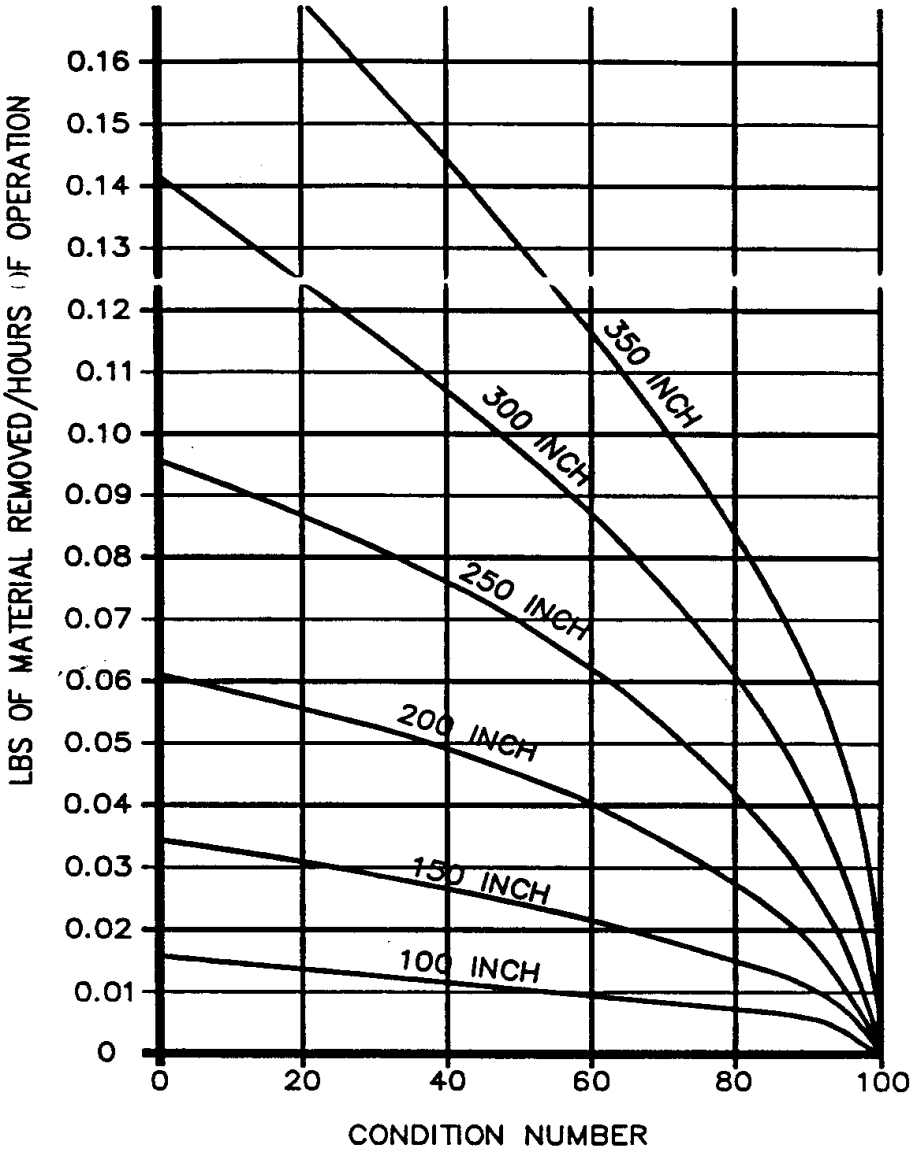


Figure 7-3C

Cavitation Condition Numbers for Large Turbines
Bottom Ring/Discharge Ring and
Draft Tube Liner Cavitation

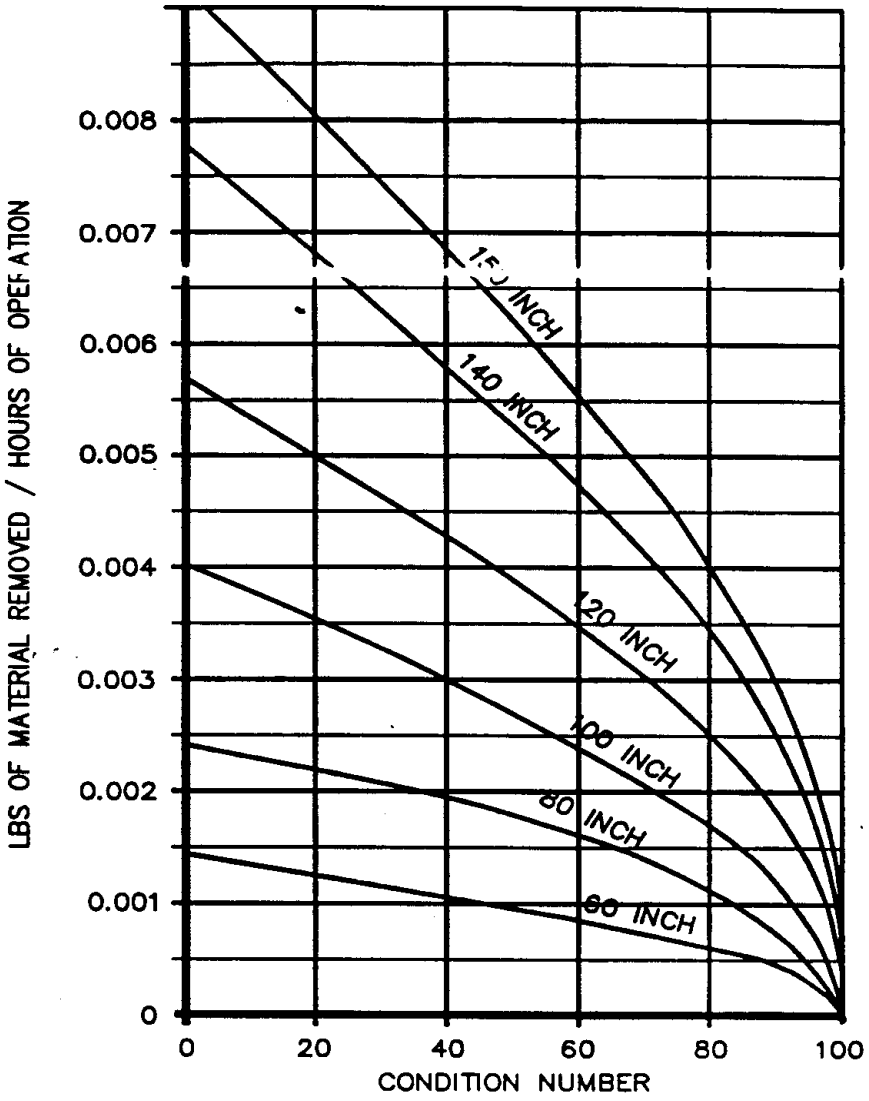


Figure 7-3D

Cavitation Condition Numbers for Small Kaplan
and Propeller Turbines
Runner Cavitation

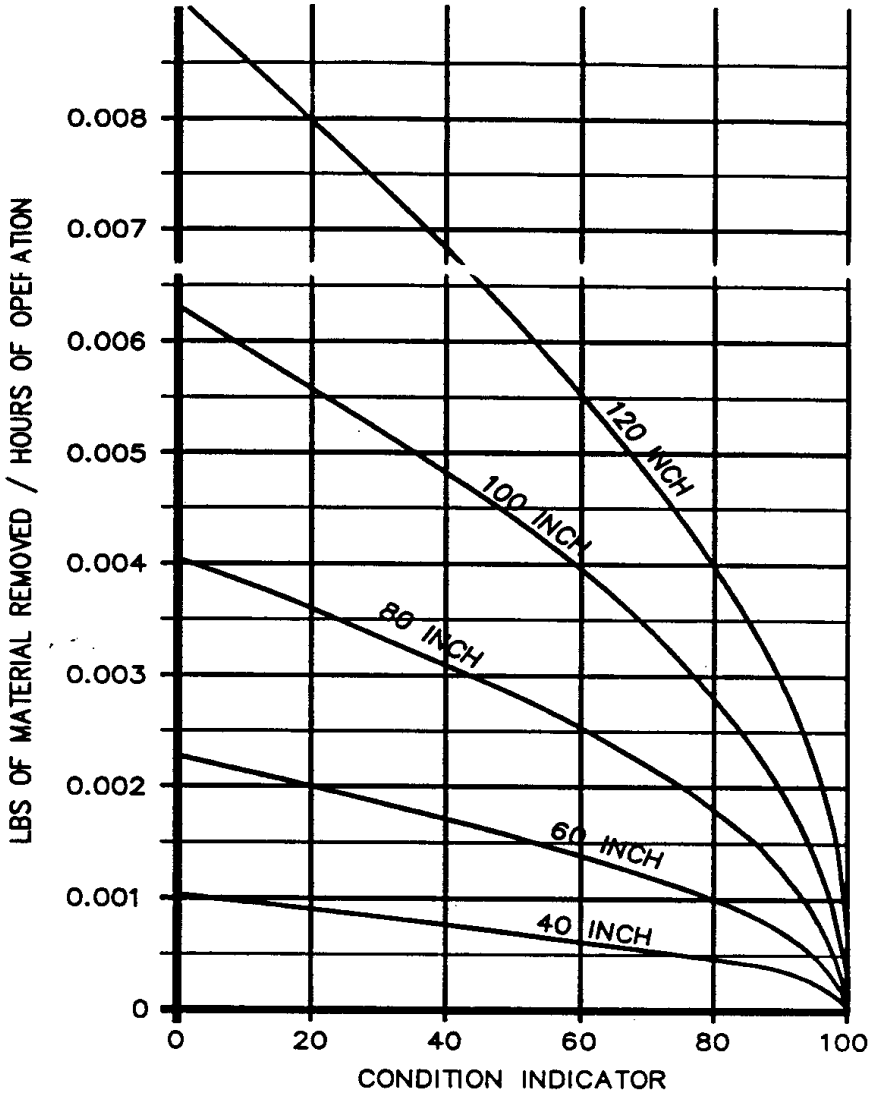


Figure 7-3E

Cavitation Condition Numbers for Small Francis Turbines
Runner Cavitation

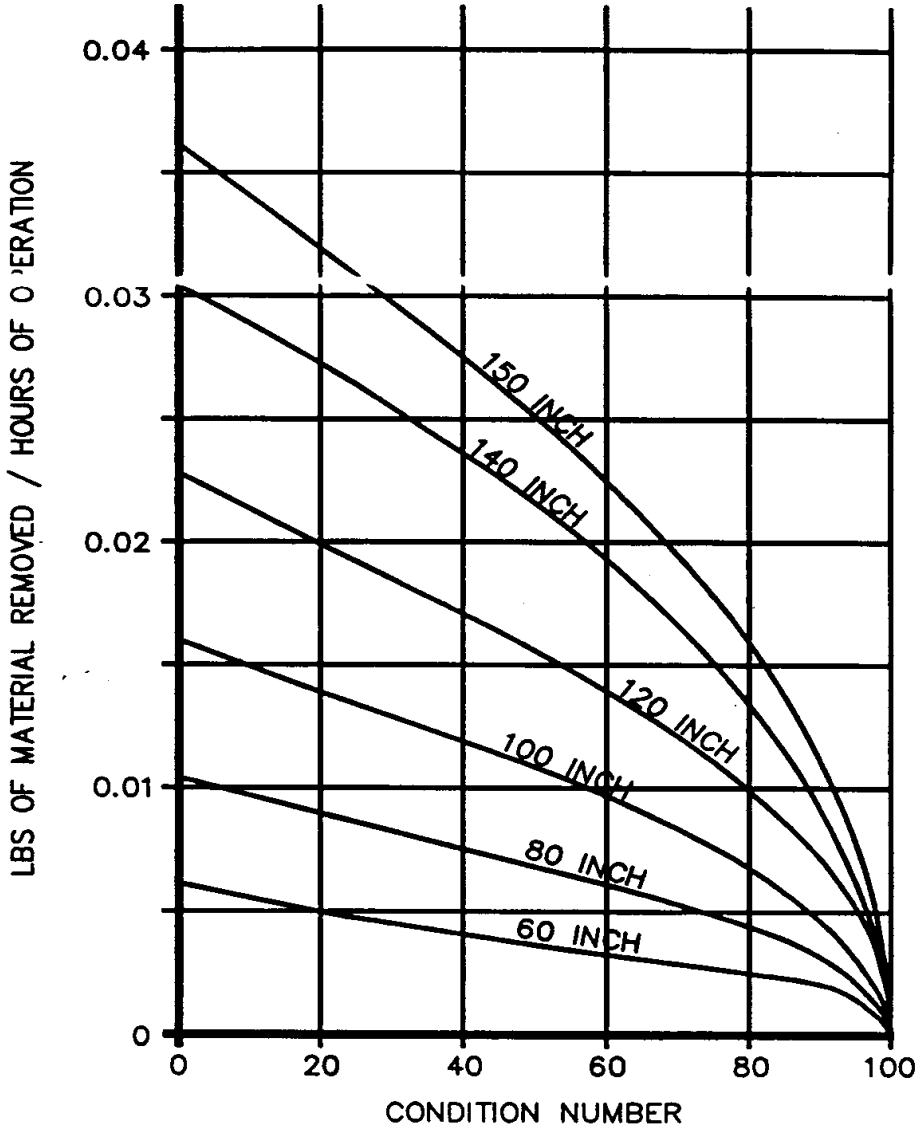


Figure 7-3F

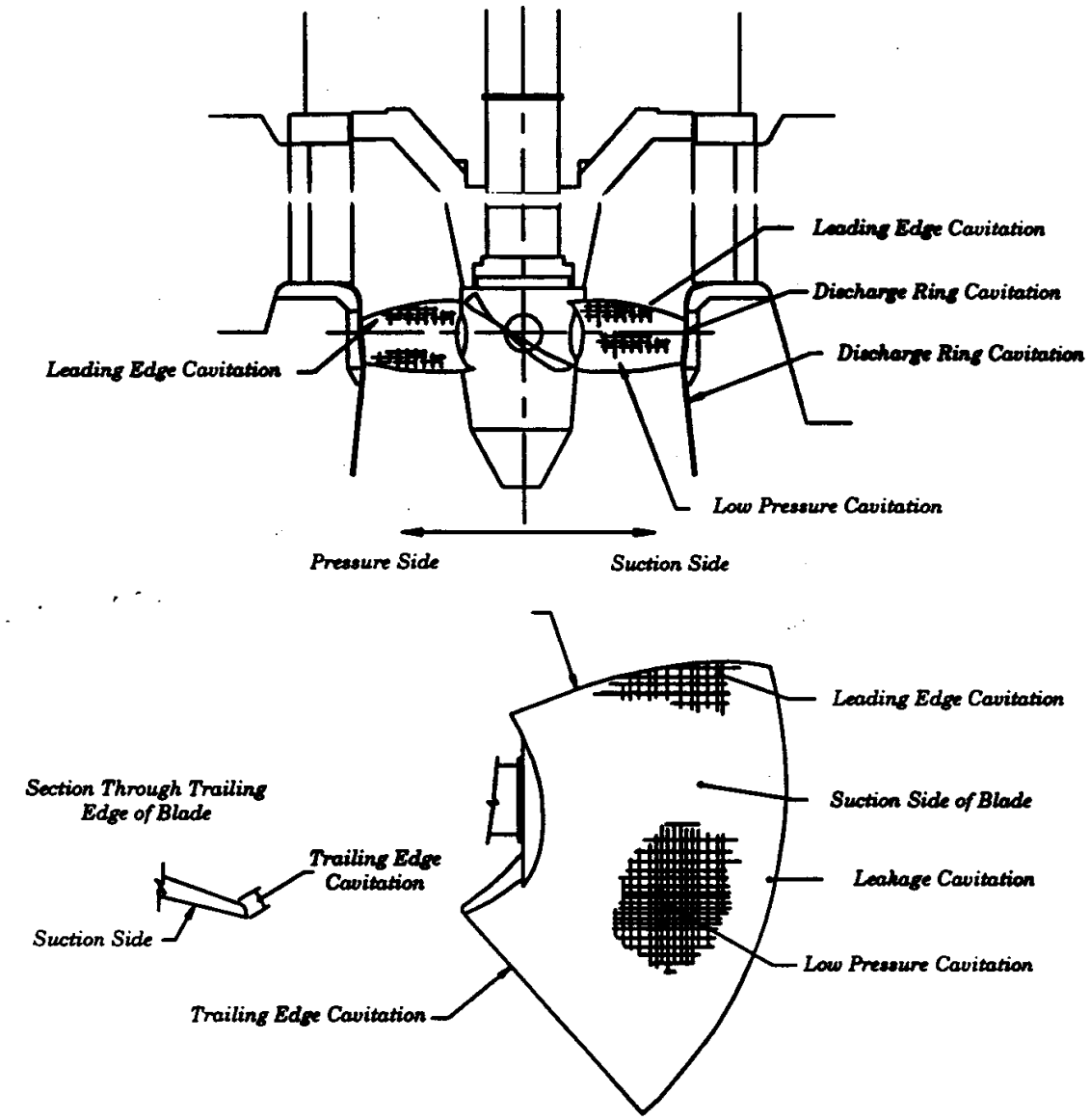
Cavitation Condition Numbers for Small Turbines
Bottom Ring/Discharge Ring and
Draft Tube Liner Cavitation

Table 7-5

Cavitation Condition Numbers for Wicket Gates and Head Cover

Maximum Pitting Depth in Inches	Condition Number
0	100
1/32	90
1/16	80
3/32	70
1/8	60
5/32	50
5/16	40
7/32	30
¼	20
Greater than ¼	10

Typical Areas of Cavitation Pitting - Kaplan and Propeller Turbines



Typical Areas of Cavitation Pitting - Francis Turbines

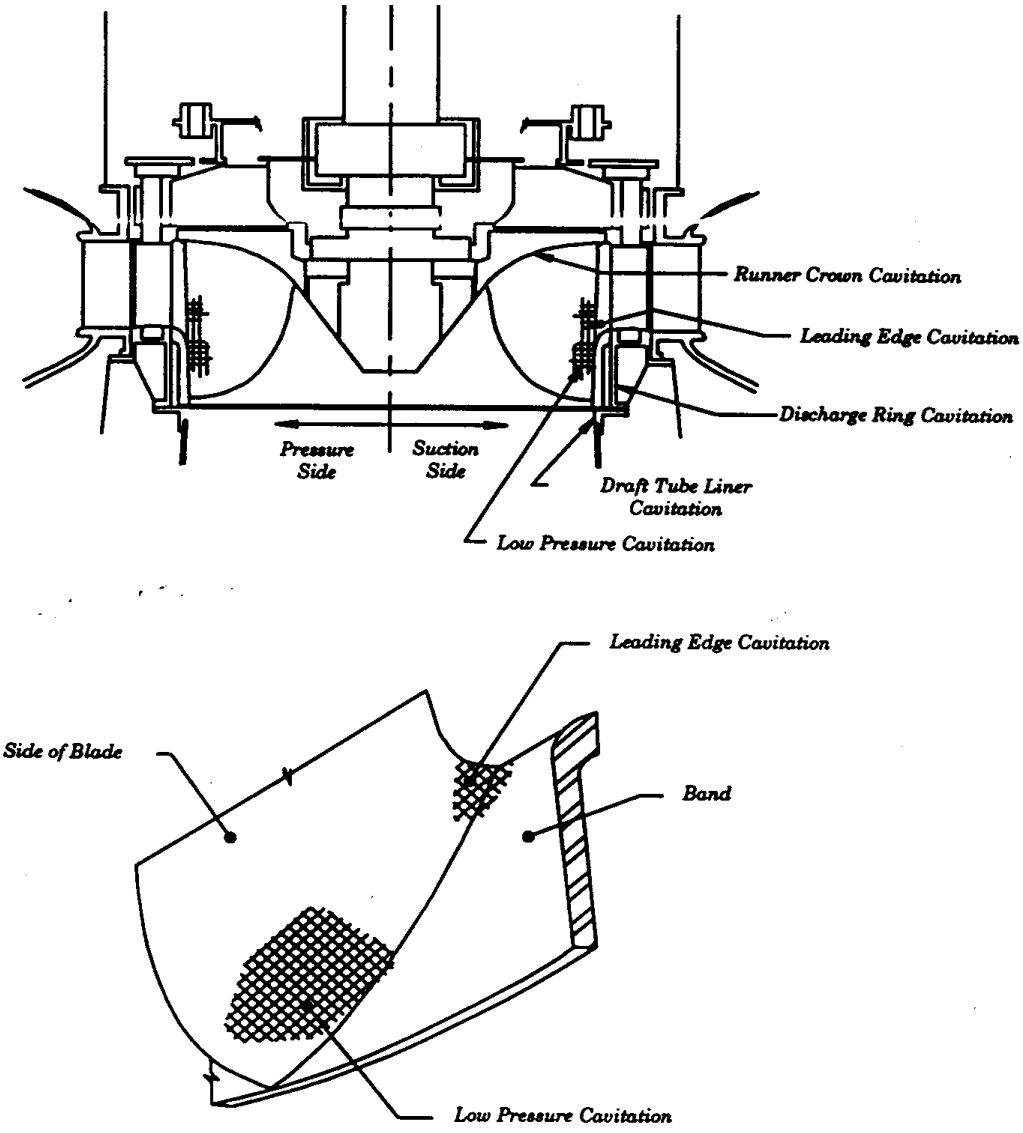


Figure 7-5

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Cavitation

Runner Diameter

150 inches

Hours of Operation

Since last repair
20,000

Project: *Old Hydro Plant* Unit No._____

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*

Location	Wt. Of Material Removed (lbs)	Max. of Depth of Pitting (in.)	Remarks	Lbs. Removed/ hr of operation	Condition Number 0-100
Blades	*80*	*1/16*			
Crown	*20*	*1/32*			
Band	*20*	*1/32*			
Total for Runner	*(A) 120*			*0.006*	*80*
Draft Tube Liner	*40*	*1/16*			
Discharge/ Bottom Ring	*500*	*3/16*	*Heavy Cavitation 1" below runner*		
Total for Discharge DT Liner	*(B) 540*	*3/16*		*0.027*	*40*
Wicket Gates		1/32			
Head Cover			*Inspection not made*		
			Cavitation Condition Index		*90*

REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 1 - Operation/Inspector Data

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*

General Information

	Date:	Operating Hours Since:	Total Energy Production Since:
Last Cavitation Inspection:	*7/3/86*	*20,000*	*1,040 GWH*
Last Cavitation Repair:	*7/3/86*	*20,000*	*1,040 GWH*

Comments on unusual operating conditions since last inspection and/or cavitation repair (e.g., extended operation at high or low head, low tailwater, high or low loading, etc.)

*Unit has operated at ra*ted point from 1986 to 1989. 1989 to 1990 unit ran at low tailwater setting and light load

Components	Inspected by:	Components Inspected:	Inspected by:	Components Inspected:	Inspected by:
Runner Blades	*INS*	Drat Tube Liner	*INS*	Bottom Ring	*INS*
Runner Band	*INS*	Discharge Ring	*INS*	Head Cover	*INS*
Runner Crown	*INS*	Wicket Gates	*INS*		

REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 2 - Summary of Cavitation

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*

This summary is calculated from data on inspection sheet 3.

	Area (in^2)	Volume (in^3)	Weight (lbs.)
Runner Blades-Suction Side (Total all blades)	_____	_____	_____
Runner Blades - Pressure Side (Total all Blades)	_____	_____	_____
Runner Band	_____	_____	_____
Runner Crown	_____	_____	_____
Draft Tube Liner	_____	_____	_____
Discharge Ring	_____	_____	_____
Wicket Gates (Total all Gates)	_____	_____	_____
Bottom Ring	_____	_____	_____
Head Cover	_____	_____	_____

Remarks:

_____

_____

Notes:

1. Volume = Area x Average Depth (if average depth is not recorded use ½ of maximum depth).

2. Weight (lbs) = Volume (in^3) x 0.283 (lbs/in^3)

REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 3 - Data

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*

Component	Location of Cavitation (identify on next 5 inspection sheets	Area (in^2)	Depth (in.) Maximum	Average

Make additional copies of this page as required.

REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 4 - Kaplan or Fixed Blade - High Pressure Side

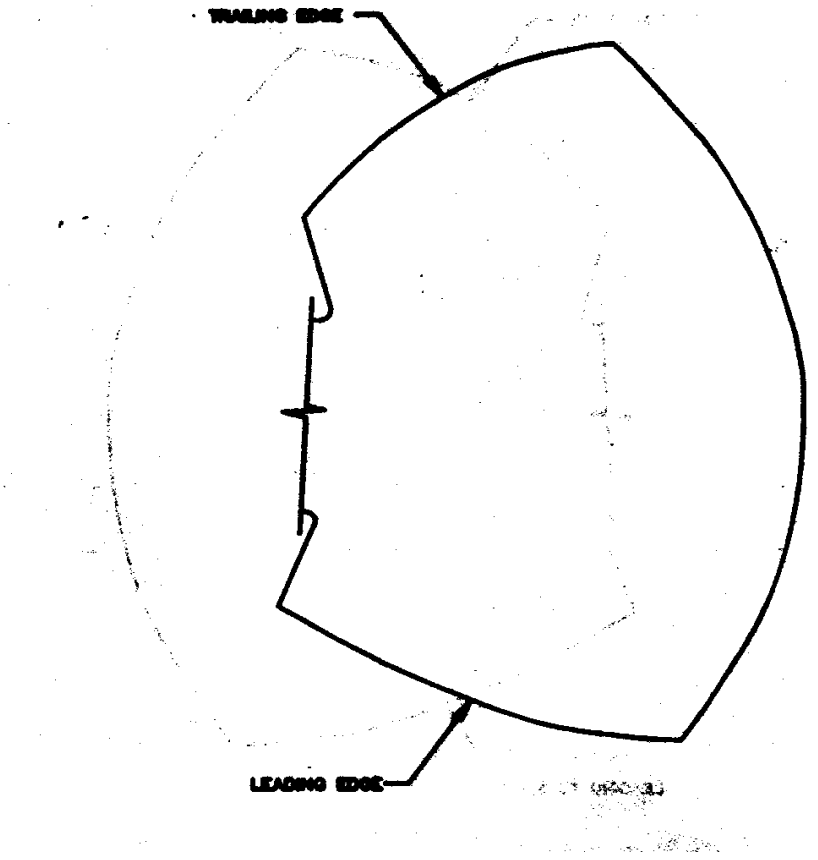
Project: *Old Hydro Plant* Unit No. *1*

Blade Number

Type of Turbine: *Francis*

_____

Prepared by: *I.N. Inspector* Date: *7/3/90*



Map Areas of Cavitation - Make One Sheet for each Blade

REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 5 - Kaplan or Fixed Blade - Low Pressure Side

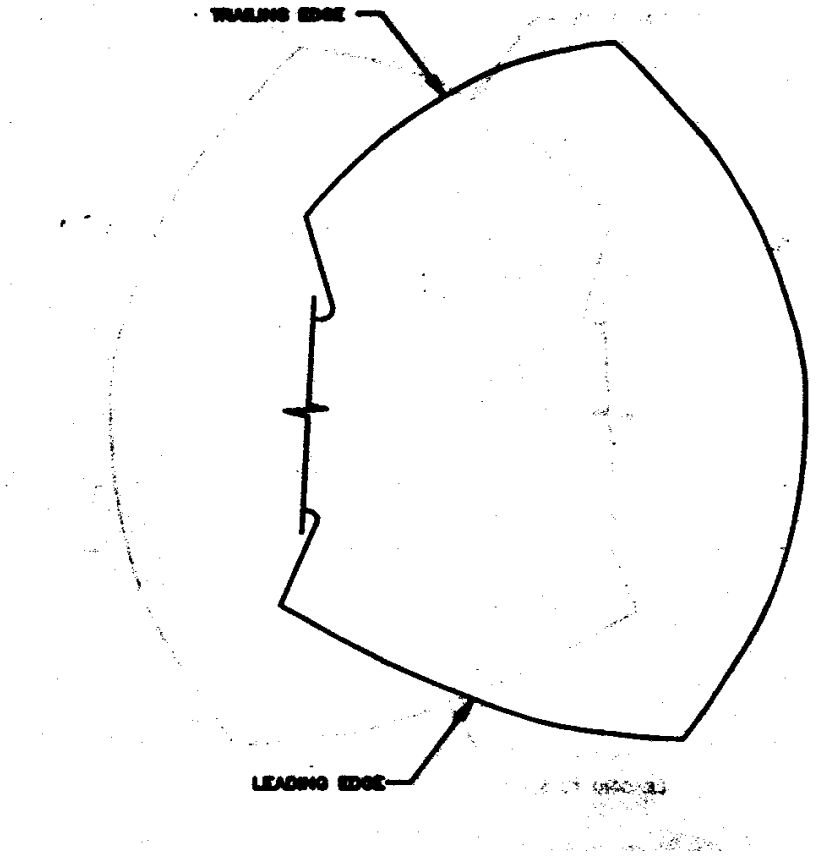
Project: *Old Hydro Plant* Unit No. *1*

Blade Number

Type of Turbine: *Francis*

_____

Prepared by: *I.N. Inspector* Date: *7/3/90*



Map Areas of Cavitation - Make One Sheet for each Blade

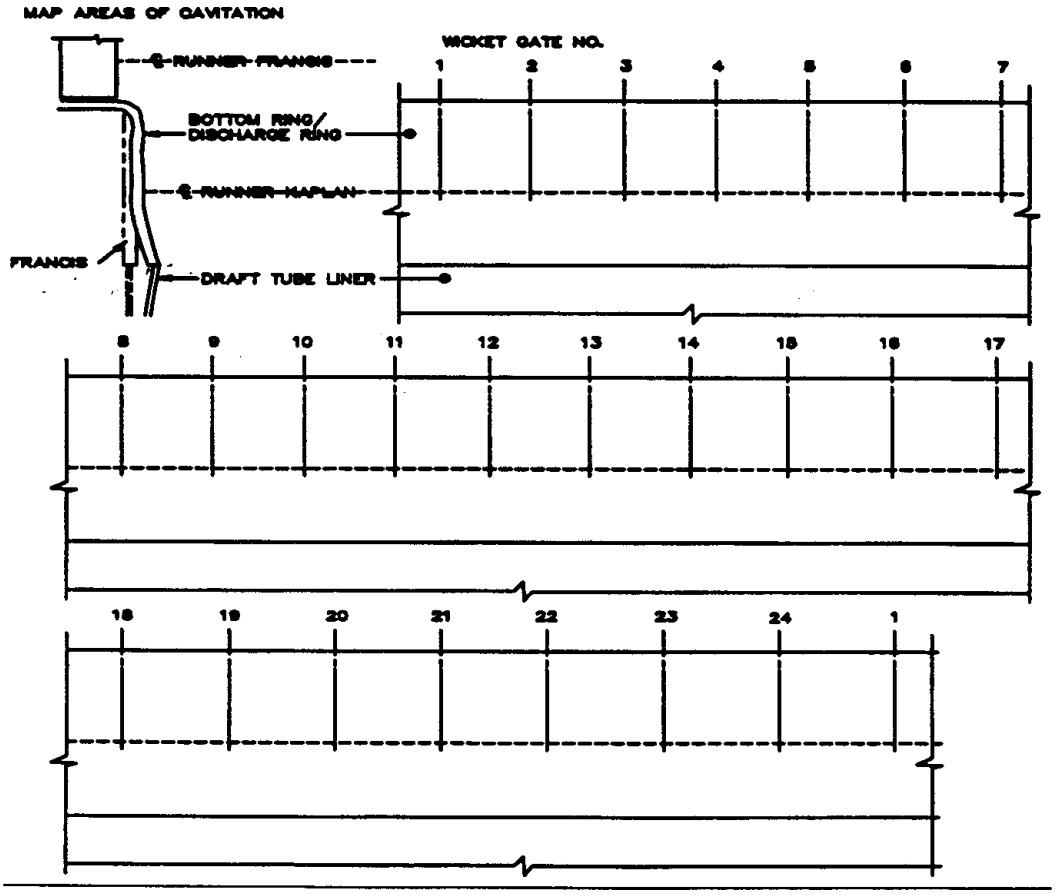
REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection Sheet

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*


MAP AREAS OF CAVITATION
WICKET GATE NO.
℄ RUNNER FRANCIS
BOTTOM RING/
DISCHARGE RING
℄ RUNNER KAPLAN
FRANCIS
DRAFT TUBE LINER
1 2 3 4 5 6 7
8 9 10 11 12 13 14 15 16 17
18 19 20 21 22 23 24 1

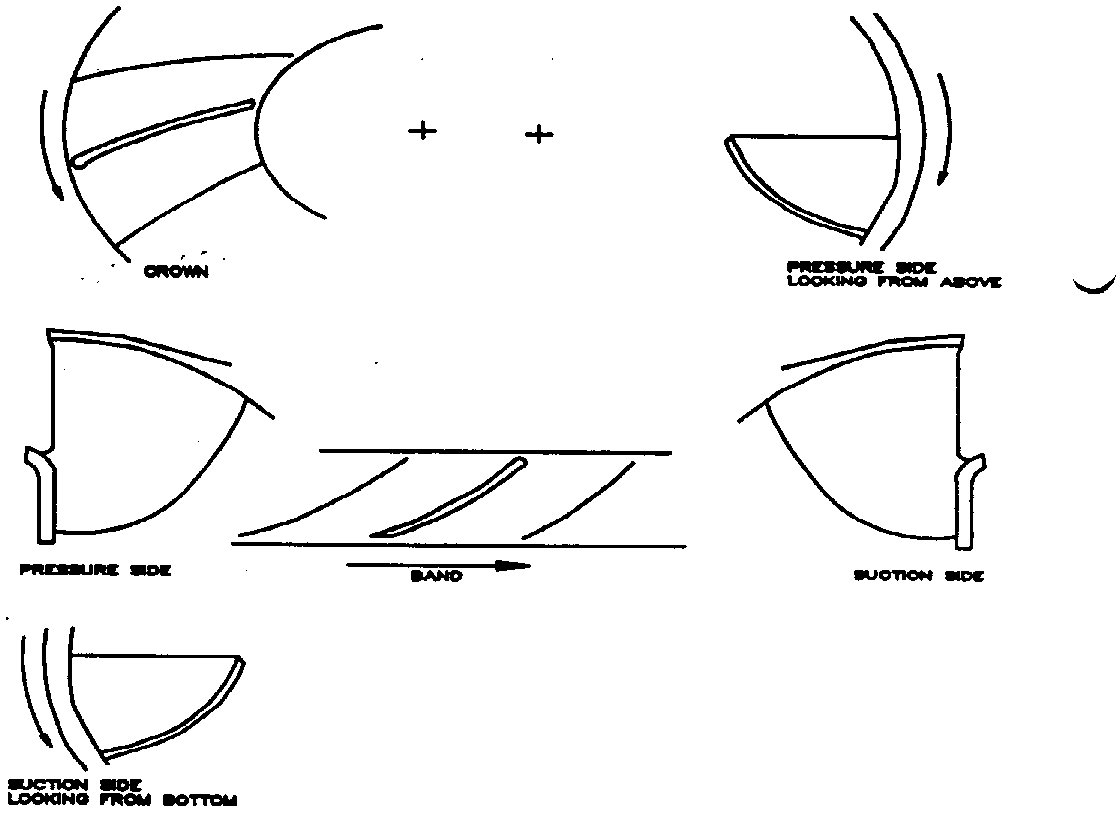
REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection Sheet

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*



Map Areas of Cavitation - Make One Sheet for each Bucket

Map Areas of Cavitation - Make One Sheet for each Bucket

REMR Hydropower Condition Indicator Program

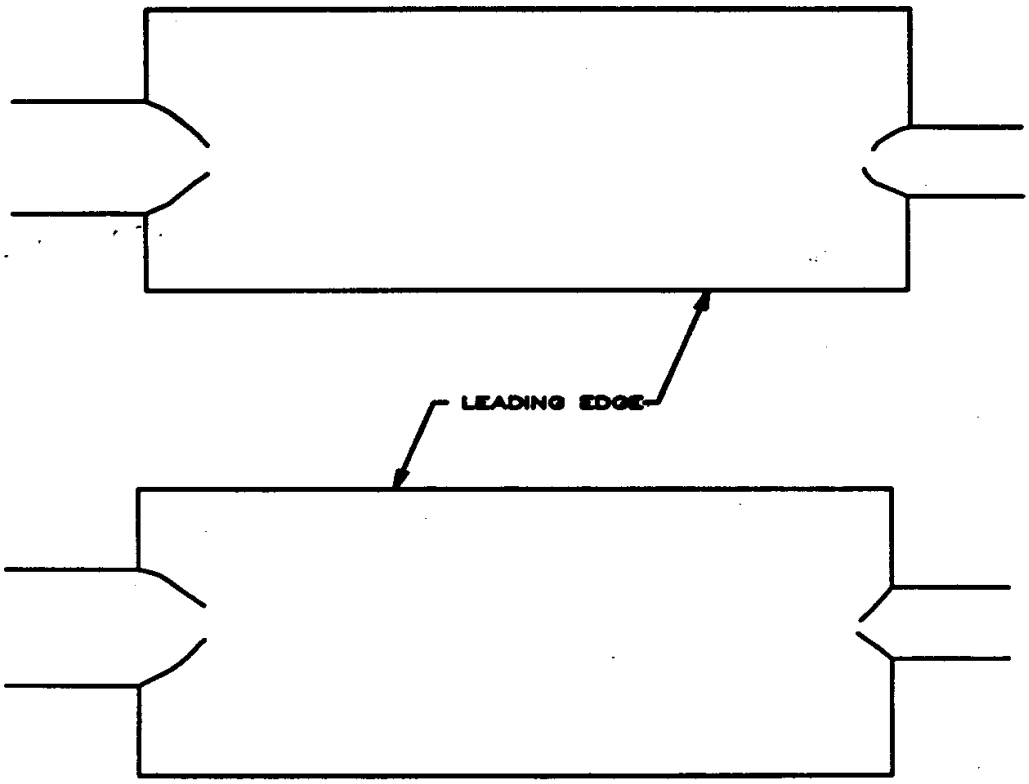
Turbine Cavitation Data Inspection
Sheet 8 - Wicket Gates

Project: *Old Hydro Plant* Unit No. *1*

Wicket Gate No. _____

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*



Map Areas of Cavitation - Make One Sheet for each Gate

Shaft Runout

Introduction

7-24. This test is used to determine the condition of the turbine based on runout of the shaft. This runout is measured at various locations with dial indicators. A condition number is assigned to each measurement based on the maximum runout recorded. This test should be used strictly as a maintenance tool, as a low score may instead be caused by an entirely different component (such as the generator rotor) being out of balance.

Instructions for Evaluation

7-25. A dial indicator should be rigidly mounted (magnetic base is acceptable) in the locations shown in Figure 7-9. Additional locations may also be used. The unit should be slowly rotated one time and runout recorded. This will establish runout when the unit is not loaded.

Next, start the unit and bring it to the desired operation point and allow the turbine to stabilize. Record MW output and head. Record runout readings on the Data-Evaluation Sheet.

Filling Out Data Evaluation Sheet

7-26. Note the location of the dial indicator in column 1. Fill in the maximum runout observed at the indicator location in column 2. Column 3 may be used for notes about the test. A condition number between 0 and 100 is assigned to each indicator location depending on the runout that is measured. Table 6 is used to determine the condition number. The condition number is placed in column 4.

The overall Runout Condition Number is the lowest condition number from column 4. This number is placed in the box in the lower right corner of the Data Evaluation Sheet. A sample of this form is shown on page D-61. Information to be completed by the field is shown in script text.

Frequency of Inspection

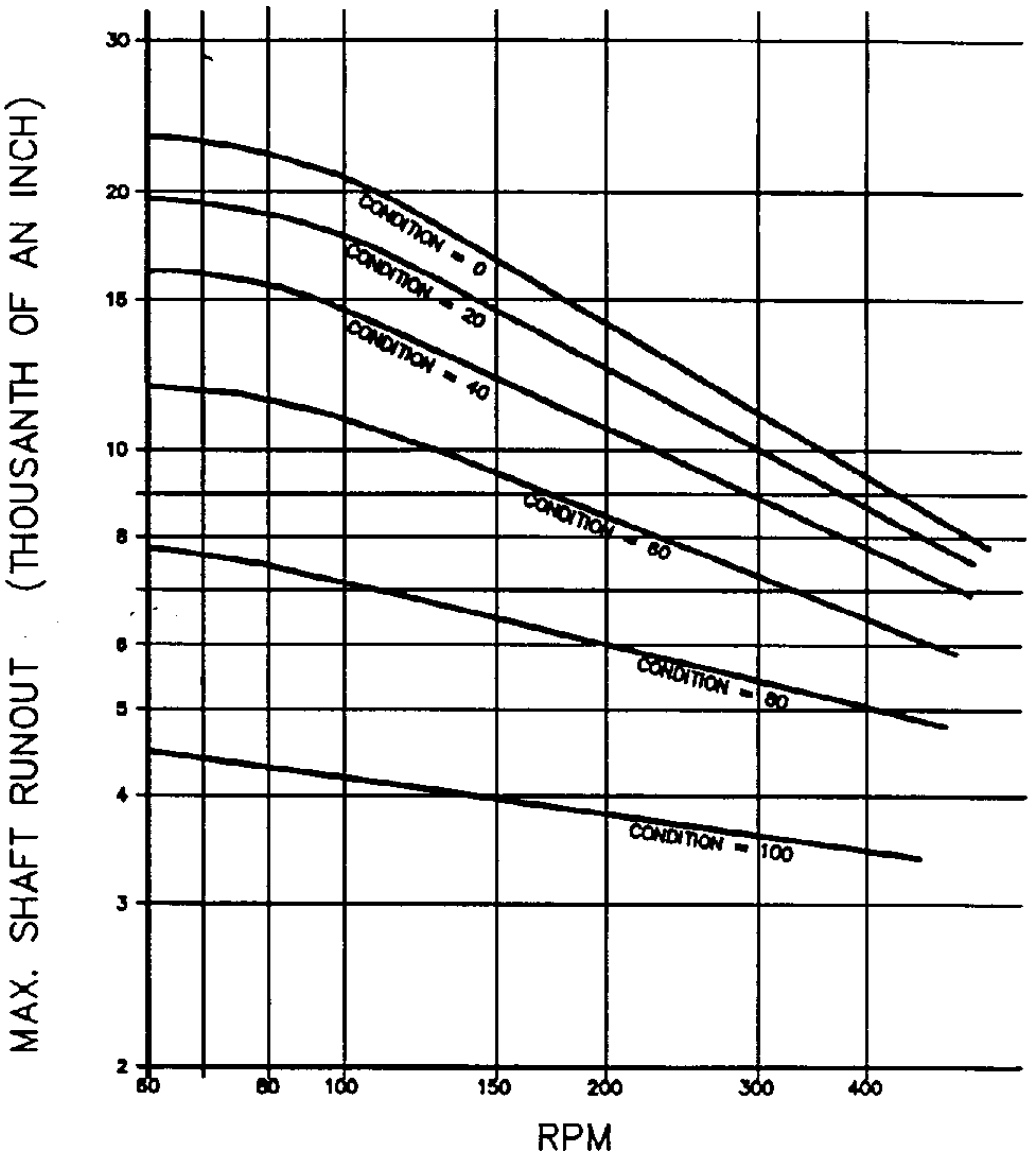
7-27. This test is optional. Runout testing usually done annually or whenever it seems warranted because of increased vibration or noise. If runouts appear excessive or are increasing with time, test more frequently.

Table 7-6

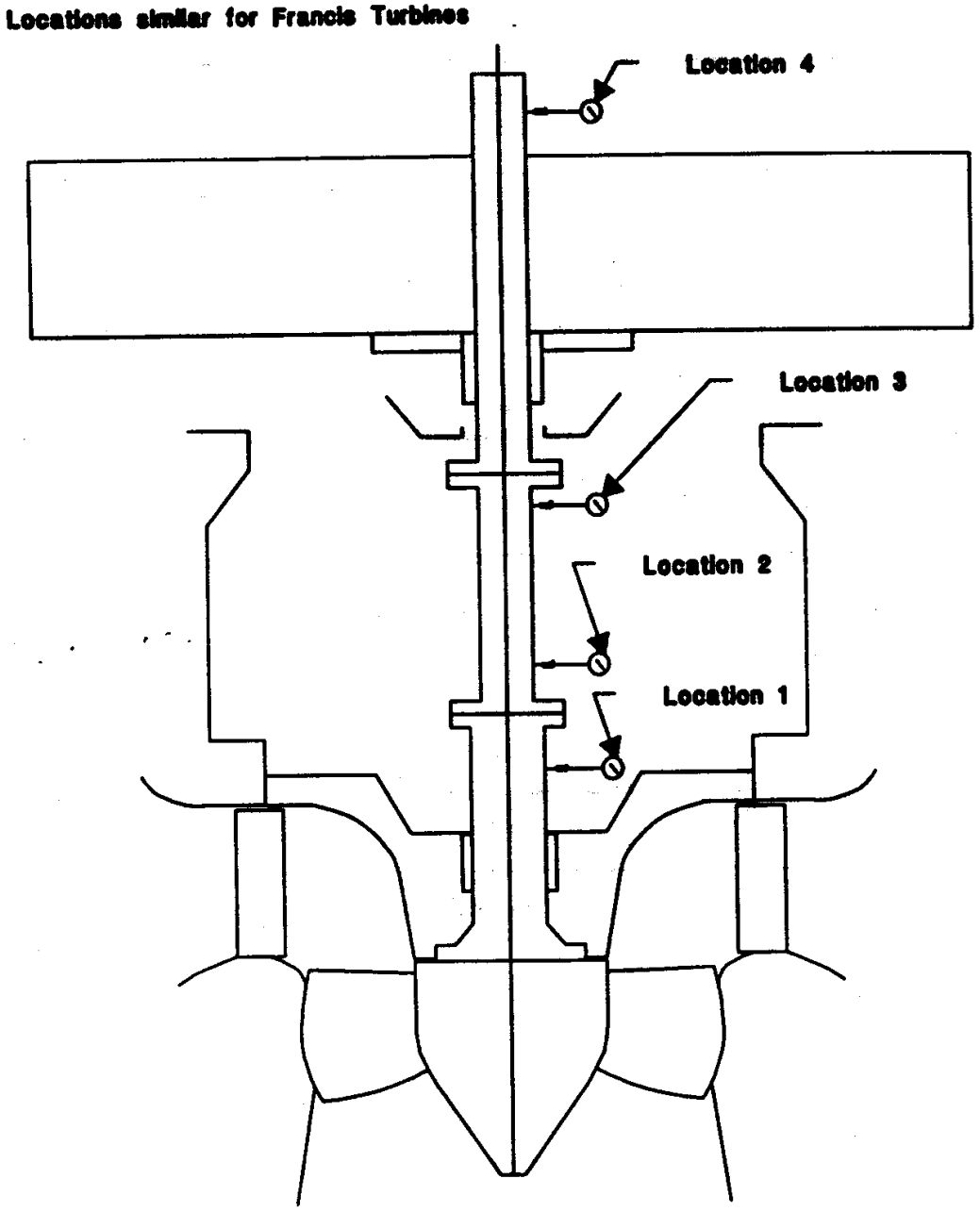
Shaft Runout

% of Design Bearing Clearance for Oil-Lubricated Bearings - or- % Change from Best Runout for Water-Lubricated Bearings	Condition Number
<10	100
30	80
50	60
70	40
>90	20

Shaft Runout -Curves for Selecting Condition Numbers for Radial Runout



Shaft Runout - Indicator Locations



REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Conditon - Shaft Runout

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*

MW Output During Test: 52 Head During Test: 190 ft Unit RPM: 128.6

Location of Probe	Maximum Runout (in)	Remarks	Condition Number 0-100
1	*0.016*	*Radial Runout*	25
2	*0.012*	*Radial Runout*	50
3	*0.008*	*Radial Runout*	80
4		*Not Measured*	
		Overall Runout Condition Index Rating:	*25*

Stick Slip Test

Introduction

7-28. This evaluation is used to measure the condition of the Kaplan blade adjustment mechanism. Test results are compiled and compared with previous results and the relative distress of the blade mechanism is determined. A condition number is assigned based upon the overall dynamic coefficient of friction and the "stickiness" of the mechanism. Stickiness is determined by the change in differential pressure across the blade servomotor piston when a small movement occurs.

Instructions for Inspection

7-29. The Stick Slip Test consists of two parts: Load Control Simulation and Dynamic Sequence. The Load Control Simulation monitors the effects of small changes in load on the governor oil pressures for each region of operation (see Figure 7-9). The Dynamic Sequence is used to measure the coefficient of friction as the load on the unit continuously changes from low load to full load and from full load back to low load. For test methods information, contact the U.S. Army Corps of Engineers Portland District (CENPP-OP).

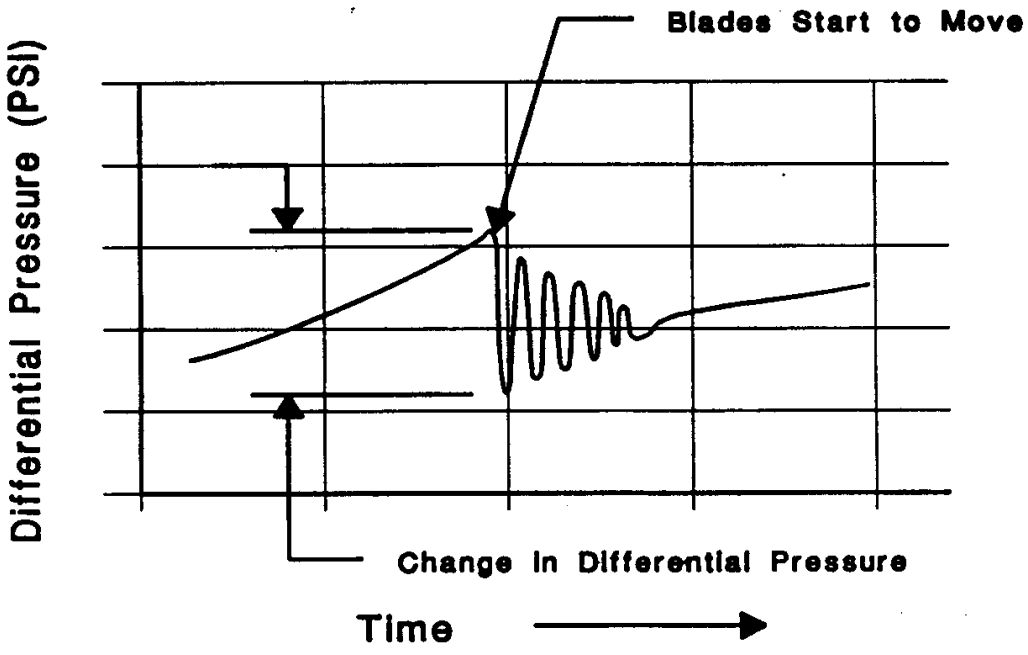


Figure 7-9

Filling Out Data Evaluation Sheet

7-30. A condition number between 0 and 100 is assigned based upon the Stick Slip test results. You may use column 1 of the Data Evaluation Sheet to enter any notes about the test. Obtain a condition number from Table 7 and a condition number from Table 8. Place the lowest of the two condition numbers in column 2. A sample of this form is shown on page [ ]. Information to be completed by the field is shown in script text.

Frequency of Test

7-31. This test is optional. Slip Stick testing should normally be performed six months to one year after a unit is initially assembled or reassembled with new bushings in place in order to establish a base line. This assures that the bearings have had a chance to "wear in." Subsequent tests should be done annually for 3 years, and as needed thereafter (once every 5 years might be appropriate). More frequent testing may be warranted if the measured values seem to be deteriorating.

Table 7-7

Load Control Simulation

Differential Pressure Change (%)	Condition Number
<10	100
30	80
50	60
70	40
>90	20

Where:

Differential Pressure Change (%)

$$= \frac{\text{PRESSURE DIFFERENTIAL (PSI) X 100}}{\text{NOMINAL SYSTEM PRESSURE (PSI)}}$$

Table 7-8

Dynamic Sequence

Average Coefficient of Friction	Condition Number
<.075	100
.1	80
.125	60
.15	40
>.175	20

Field Performance Tests

Introduction

7-32. This evaluation is used to determine the current operating performance of the turbine as compared to prior tests, original guarantees, and modern equipment capabilities. The entire operating range is examined with particular emphasis on maximum efficiency and maximum (full gate) power output.

Experienced personnel are required to perform these tests. Where previous test data is available, the earlier test conditions should be duplicated as much as possible. The HDC should be consulted prior to conducting a field performance test.

Instructions for Evaluation

7-33. Field performance tests should be conducted in accordance with ASME PTC-18. Once testing has been completed, the results can be compared with earlier tests or with manufacturer data for new or replacement runners.

Differences in efficiency must be evaluated cautiously. Measurement methods affect the magnitude of the efficiency. Most earlier performance tests were done by the original version of the Pressure-Time Method using the Gibson apparatus (Gibson Method). Current tests performed by HDC use transducers (Transducer Method) instead of the Gibson apparatus. There is a 1 1/2 percent difference in measured efficiency between the two methods. The Gibson Method will yield the higher efficiency of the two. Therefore, the data must be adjusted accordingly when the method of discharge measurement is different between the two tests.

Similar differences exist between other methods of the measurement such as current meters, dye dilution, ultrasonic salt velocity, etc. As a result, similar adjustments will need to be made prior to comparing the data. The EPRI Reports on Comparative Flow Measurements at Kootenay Canal and Grand Coulee Pumping/Generating Plant can be used as a guide for adjustment.

Index test results should only be compared with the Index test results from a previous test using the same set of taps on the same unit. Differences in calibration from one set of taps to another are unpredictable and cannot be used for comparison of efficiency.

Where previous test data is not available, current manufacturer data on new units may be used as a reference. The same precautions with respect to efficiency should be used, as most manufacturers base their efficiency guarantee on the method of discharge measurement used during the acceptance test.

Comparison of power output at full gate can generally be made without difficulty. Since the type of measurement method will not affect the result, differences in full gate output can be assigned a value from the table.

Filling Out Data Evaluation Sheet

7-34. A condition number between 0 and 100 is assigned based on the percent decrease in power or efficiency. Enter the original unit performance in column 1, if available. If the unit has not been previously tested, enter the manufacturer data for new units in column 2, enter the current unit performance in column 3. Calculate the percent performance decrease and condition number using Table 7-9 and enter them in columns 4 and 5 respectively. A sample of this form is shown on page D-70. Information to be completed by the field is shown in script text.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Field Performance Test

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*

	Unit Performance				
	Original	New Unit	Current	Performance Loss	Condition Number 0-100
Power	*80 MW*		*78 MW*	*2.5%*	*60*
Efficiency	*92.6%*		*89.54%*	*3.3%*	*47*
				Overall Performance Condition Index Rating:	*47*

Frequency of Evaluation

7-35. This test should be performed whenever considering a turbine upgrade, turbine replacement, or generator rewind. For Kaplan turbines, this test should be performed when on-cam performance is suspected to be deteriorating.

Table 7-9

Field Performance Tests

Decrease (%)	Condition Number
<.5	100
.5	90
1	67
3	50
5	30
8	10

Where Percent Performance Decrease = the lowest of the results of the following equations.

1) $\frac{\text{(Original Full Gate Power - Current Full Gate Power)}}{\text{Original Full Gate Power}} \times 100$

2) $\frac{\text{(Original Installed Maximum Eff. - Current Peak Eff.)}}{\text{Original Installed Maximum Efficiency}} \times 100$

Surface Condition

Introduction

7-36. This indicator measures the condition of the paint coating and its ability to withstand corrosion. The coating is the primary defense against deterioration and must be rated properly. Coatings commonly fail by pitting, blistering, flaking and peeling from wear and/or abrasion. Discoloration of a coating is usually not serious, since the coating is still functional.

Instructions for Inspection

7-37. In order to avoid unnecessary unwatering of units, it is only necessary to inspect one of the units. In most cases, checking one unit will provide a reasonably good indication of the condition of the other units. If some units have been rehabilitated more recently than others, check one of the ones that was rehabilitated less recently.

Once the slot has been unwatered, check all visible areas of the following items:

Spiral Case (Francis only)
Stay Ring and Vanes
Head Cover and Bottom Ring
Discharge Ring (Kaplan only)
Draft Tube
Runner
Wicket Gates

The surface condition number is determined using Table 7-10 as a guide.

Table 7 - 10

Surface Condition of Paint Film

a.	Smooth, no blisters, flaking or pinholes	100
b.	Minor blisters, pitting and small areas of erosion	75
c.	Numerous blisters, moderate pitting, corrosion and/or erosion around stainless steel repair work	50
d.	Large areas of corrosion and pitting. Blisters over 1/8" high, and/or heavy erosion.	25

Filling Out Data Evaluation Sheet

7-38. Write in column 1 the item being inspected. List in column 2 the location(s) of the area(s) of surface problems on that item. Use column 3 to estimate the percent of area showing defects/corrosion/erosion. Describe the defects /corrosion/erosion in detail in column 4, and record the condition number in column 5. The condition number to be noted in the lower right hand corner of the Data Evaluation Sheet is the lowest of the condition numbers recorded in column 5. A sample Data Evaluation Sheet is shown on page D-74. Information to be completed by the field is shown in script text.

Frequency of Evaluation

7-39. This test should be done whenever water passages are unwatered. Therefore, this test will be performed on each unit at least once a year during its annual inspection.

REMR Hydropower Condition Indicator Program

Turbine Data Evaluation Sheet
Surface Condition

Project: *Old Hydro Plant* Unit No. *1*

Type of Turbine: *Francis*

Prepared by: *I.N. Inspector* Date: *7/3/90*

Item	Location	Percent of Area Damage	Remarks	Condition Number 0-100
			Surface Condition Index	

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Turbine Condition

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

Item	Date of inspection or test	Remarks	Condition No. 0-100
Component Damage			
Oil Loss			
Blade Cracks			
Cavitation			
Shaft Runout			
Stick Slip			
Field Performance Tests			
Surface Condition			
		Overall Turbine Condition Index Rating	

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Breakage/Repair/Wear

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

Item	Date of inspection or test	Remarks	Condition No. 0-100 based and Breakage and Repair	Condition No. 0-100 based on Wear
Runner				
Head Cover				
Wicket Gates				
Wicket Gate Mechanism				
Servomotors				
Shaft				

Overall Component Damage Condition Index Rating:

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Oil Usage

Runner Diameter _____ inches

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

Oil System	Oil Addition (Gal/Year)	Location of Leakage (if Known)	Remarks
Intermediate Turbine Guide Bearing (If applicable)			
Lower Turbine Guide Bearing			
Gate Servomotor(s)			
Blade Servomotor			
Kaplan Hub (if applicable)			
Total Leakage (Gal/Year)			

Note: Attach oil records

Relative Oil Usage = Gal/Yr/Runner Dia.^{2}

Oil Usage Condition Index Rating

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Blade Cracks

Runner Diameter ____ Inches

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

Blade Number	Crack Number	Length of Crack in Inches	Zone	Remarks	Condition Number 0-100
				Overall Blade Crack Condition Index Rating	

REMR Hydropower Condition Indicator Program

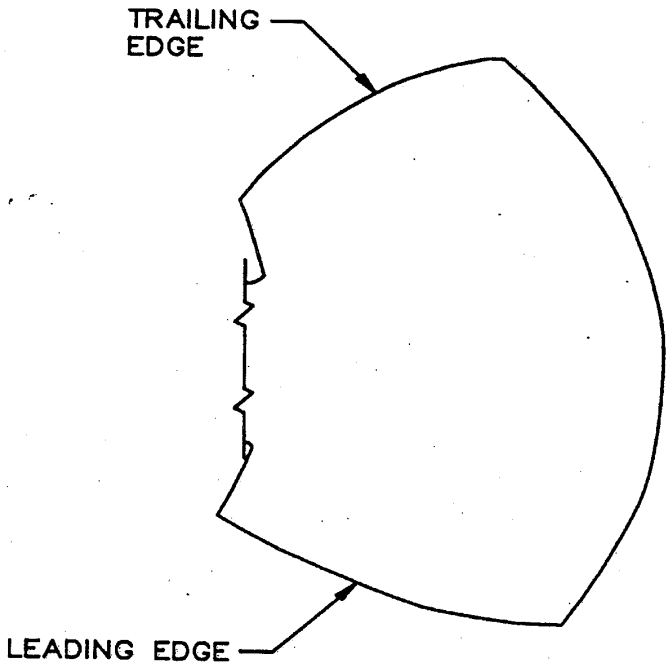
Turbine Blade Crack Inspection Sheet
High pressure Side of Kaplan or Fixed Blade

Blade Number _____

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____



Identify location and length of cracks.
Make one sheet for each blade.

REMR Hydropower Condition Indicator Program

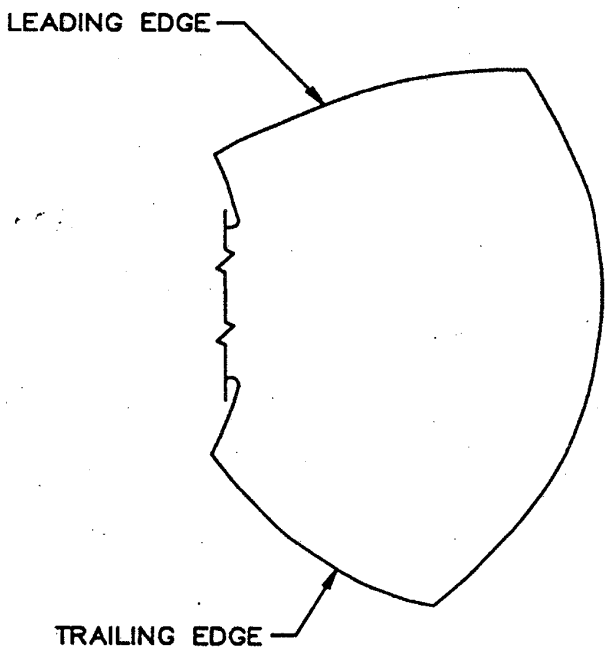
Turbine Blade Crack Inspection Sheet
Low Pressure Side of Kaplan or Fixed Blade

Blade Number _____

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____



Identify location and length of cracks.
Make one sheet for each blade.

REMR Hydropower Condition Indicator Program

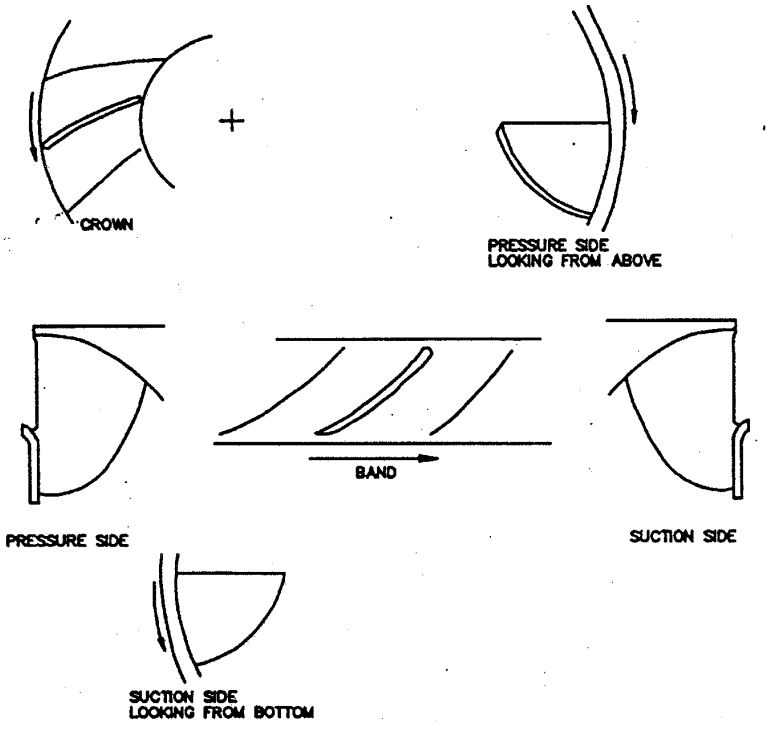
Turbine Blade Crack Inspection Sheet
Francis Runner

Blade Number _____

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____



Identify location and length of cracks.
Make one sheet for each bucket.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Cavitation

Runner Diameter
____ inches
Hours of Operation Since Last Repair
_____

Project: _____ Unit No. _____
Type of Turbine: _____
Prepared by: _____ Date: _____

Location	Wt. Of Material Removed (lbs)	Max. of Depth of Pitting (in.)	Remarks	Lbs. Removed/hr. of operation	Condition Number 0-100
Blades					
Crown					
Band					
Total for Runner	A				
Draft Tube Liner					
Discharge/ Bottom Ring					
Total for Discharge DT Liner	B				
Wicket Gates					
Head Cover					
				Cavitation Condition Index	

REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 1 - Operation/Inspector Data

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

General Information

	Date:	Operating Hours Since:	Total Energy Production Since:
Last Cavitation Inspection:			
Last Cavitation Repair:			

Comments on unusual operating conditions since last inspection and/or cavitation repair (e.g., extended operation at high or low head, low tailwater, high or low loading, etc.)

_____

_____

_____

Components Inspected:	Inspected by:	Components Inspected:	Inspected by:	Components Inspected:	Inspected by:
Runner Blades	_____	Drat Tube Liner	_____	Bottom Ring	_____
Runner Band	_____	Discharge Ring	_____	Head cover	_____
Runner Crown	_____	Wicket Gates	_____		
Bottom Ring	_____	Head Cover	_____		

REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 2- Summary of Cavitation

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

This summary is calculated from data on inspection sheet 3.

	Area (in^2)	Volume (in^3)	Weight (lbs.)
Runner Blades-Suction Side (Total all blades)	_____	_____	_____
Runner Blades - Pressure Side (Total all Blades)	_____	_____	_____
Runner Band	_____	_____	_____
Runner Crown	_____	_____	_____
Draft Tube Liner	_____	_____	_____
Discharge Ring	_____	_____	_____
Wicket Gates (Total all Gates)	_____	_____	_____
Bottom Ring	_____	_____	_____
Head Cover	_____	_____	_____

Remarks:

_____

_____

Notes:

1. Volume = Area x Average Depth (if average depth is not recorded use ½ of maximum depth).
2. Weight (lbs) = Volume (in^3) x 0.283 (lbs/in^3)

REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 3

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

Component	Location of Cavitation (identify on next 5 inspection sheets	Area (in^2)	Depth (in.) Maximum	Average

Make additional copies of this page as required.

REMR Hydropower Condition Indicator Program

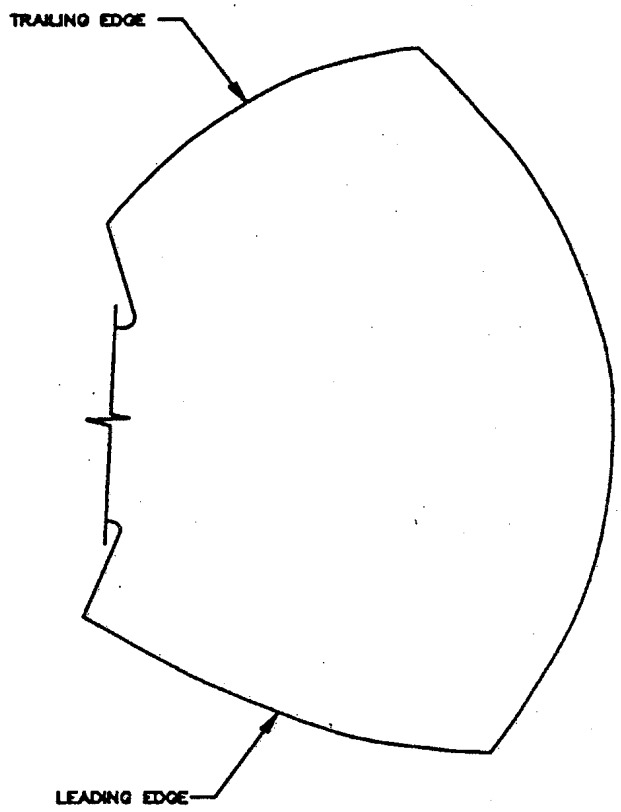
Turbine Cavitation Data Inspection
Sheet 4 - Kaplan or Fixed Blade - High Pressure Side

Blade Number _____

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____



Map areas of cavitation - make one sheet for each Blade.

REMR Hydropower Condition Indicator Program

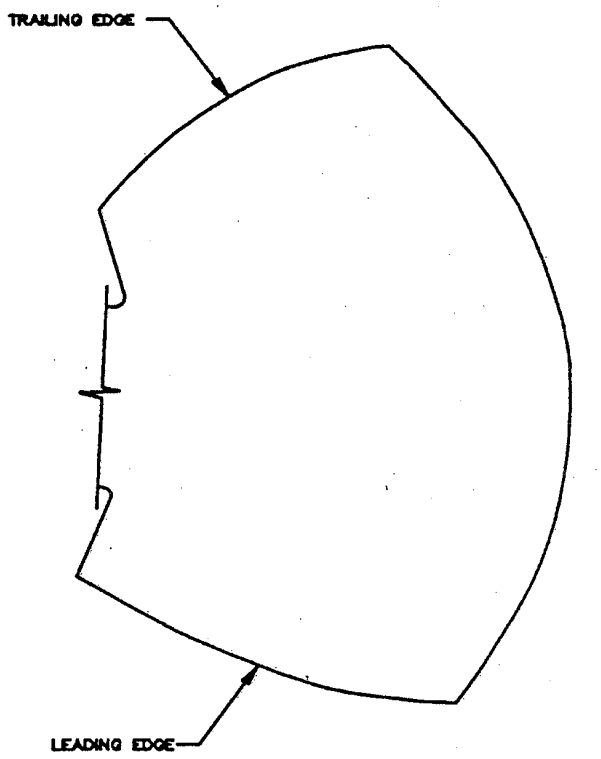
Turbine Cavitation Data Inspection
Sheet 5 - Kaplan or Fixed Blade - Low Pressure Side

Blade Number _____

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____



Map areas of cavitation - make one sheet for each Blade.

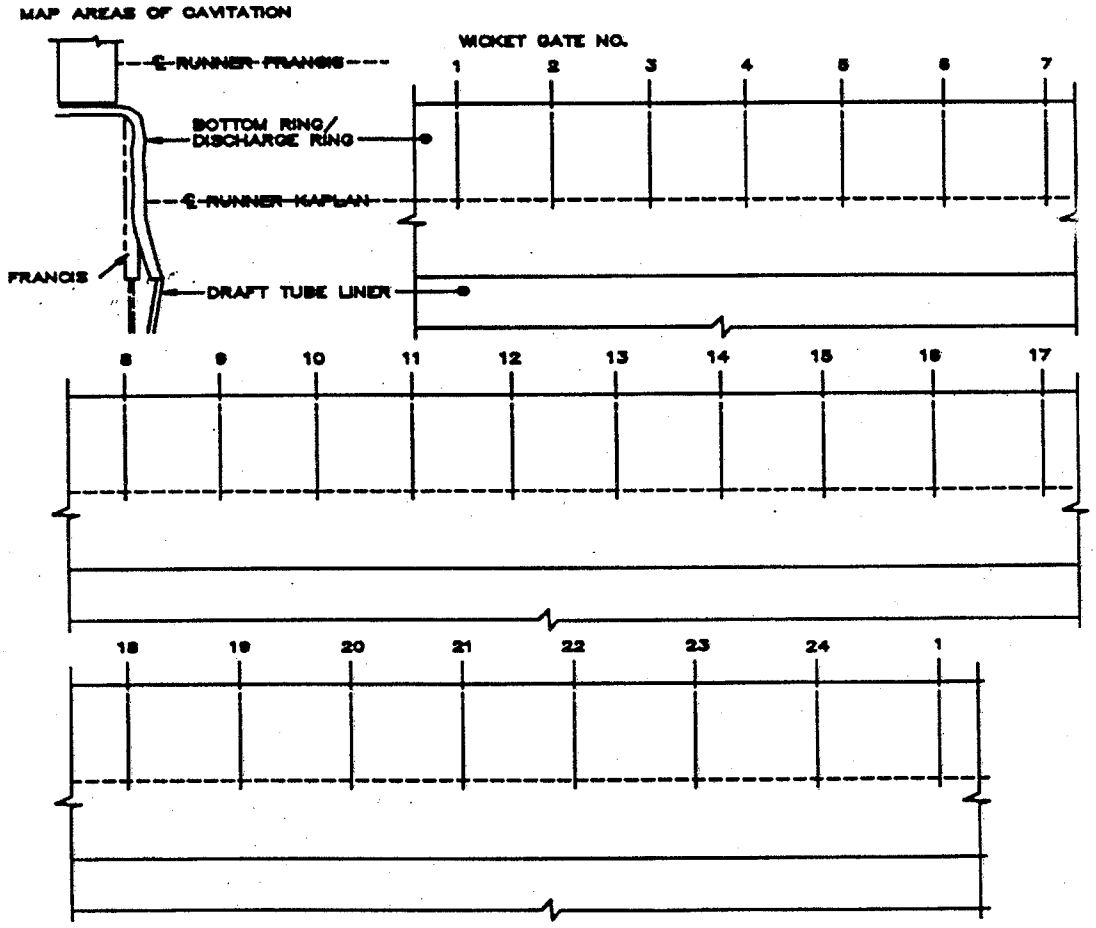
REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection Sheet

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____



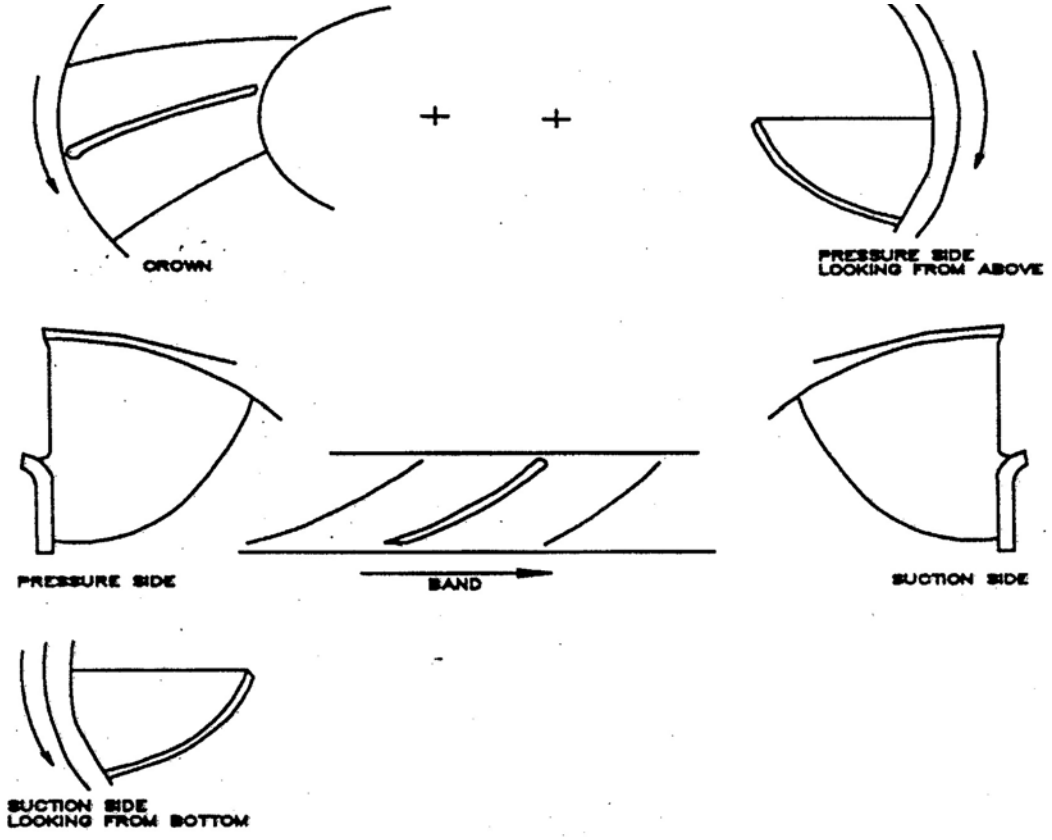
REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection Sheet

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____



Map areas of cavitation - make one sheet for each Bucket.

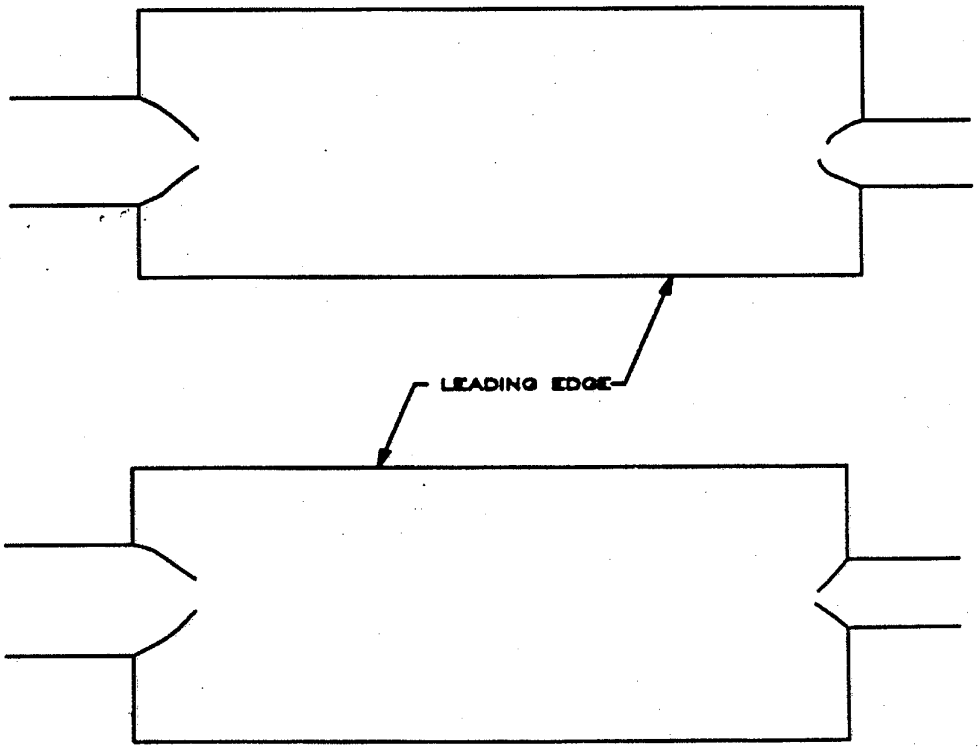
REMR Hydropower Condition Indicator Program

Turbine Cavitation Data Inspection
Sheet 8 - Wicket Gates

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____



Map areas of cavitation - make one sheet for each Gate.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Shaft Runout

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

MW Output During Test: ___Head During Test: ___ ft Unit RPM: ____

Location of Probe	Maximum Runout (in)	Remarks	Condition Number 0-100
1			
2			
3			
4			
		Overall Runout Condition Index Rating:	

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Turbine Condition - Field Performance Test

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

	Unit Performance				
	Original	New Unit	Current	Performance Loss	Condition Number 0-100
Power					
Efficiency					
Overall Performance Condition Index Rating:					

REMR Hydropower Condition Indicator Program

Turbine Data Evaluation Sheet
Surface Condition

Project: _____ Unit No. _____

Type of Turbine: _____

Prepared by: _____ Date: _____

Item	Location	Percent of Area Damaged	Remarks	Condition Number 0-100
			Surface Condition Index	

PART IX: INTAKE VALVES

Explanation of Program

9-1. The overall condition number is a number between 0 and 100 which will be used to define the present condition of a powerhouse intake valve. The number will be used in the REMR Condition Index Scale which is shown below.

The overall valve condition number is calculated from four condition index numbers. These four condition numbers are determined from various tests and inspections done on an intake valve.

Condition Index Scale

Value		Condition Description
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate
25-39	Poor	Serious deterioration in at least some portions of equipment. Function is inadequate.
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Figure 9-1

The two condition indices selected are: water seal leakage and oil seal leakage (spherical valve only).

Explanation of Format

9-2. The condition indices all have a similar format. The first sheet is an explanation sheet which describes the test or inspection, gives instructions on doing the test or inspection, explains how to fill out the data-evaluation sheet and gives the recommended frequency of doing the test or inspection. Next there are tables or figures which are used to determine a condition number based on the results of an inspection or test. Following this is the data evaluation sheet where information is recorded and calculations are made. Also attached is a sample data evaluation

sheet. The last sheets are specific inspection sheets used for mapping damage or defects. Some indices may not have evaluation sheets.

Explanation of Method

9-3. A condition number between 0 and 100 is determined for each condition index based on the results of tests and inspections. Each explanation sheet gives instructions on testing and evaluation. The overall condition number for the valve is the lowest value of any of the condition index values.

Overall Valve Condition

Introduction

9-4. The overall value condition is calculated using two condition indicators: water seal leakage and oil seal leakage (spherical valve only). Each indicator is assigned a condition number. The condition numbers are calculated based on the results of various tests and inspections which are discussed later.

Filling Out Data-Evaluation Sheet

9-5. Column 1 lists the two condition indicators which are used for evaluation. Others may be added in the future. Fill in the date the test or inspection was made in Column 2. Put in any notes or remarks about the condition in Column 3. For instance, if the condition number for a condition index was low, note the reason for it being low. Put the condition number or a particular condition index in Column 4. This number is obtained from the box in the lower right corner of the data evaluation sheet for each individual indicator.

The overall valve condition number is the lowest condition number for any of the indicators. This number is placed in the box in the lower right corner of the data evaluation sheet. A sample of the overall valve condition data evaluation sheet is shown on page 3. Information that would be completed by the field is shown in script text.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Valve Condition

Project: *Old Hydro Plant* Unit No. ____

Type of Turbine: *Spherical*

Prepared by: *I.N. Inspector* Date: *7/3/90*

Item	Date of inspection or test	Remarks	Condition No. 0-100
Water Seal Leakage	*7/3/90*		70
Oil Seal Leakage	*7/3/90*		*68*

Water Seal Leakage

Introduction

9-6. This inspection is used to determine the condition of the intake valve based on water leakage through the valve seal. A condition number is assigned based on the leakage quantity and the valve size.

Instructions for Inspection

9-7. The turbine scroll case or area downstream of the valve should be unwatered and secured for possible entry by project personnel. The amount of leakage can be determine in one of two ways. If there is easy access to the scroll case drain, then the drain can be opened and the amount of water exiting the drain can be measured. This could be done with a bucket and a stop watch if the piping drains to the draft tube. If the drain is hard to get at, then a small dam with a weir could be set up in the scroll case or penstock downstream of the valve to collect and measure the water leakage across the valve. For spherical valves with upstream seals, the valve body drain could be used. The results should be recorded in cubic feet per minute on the data evaluation sheet.

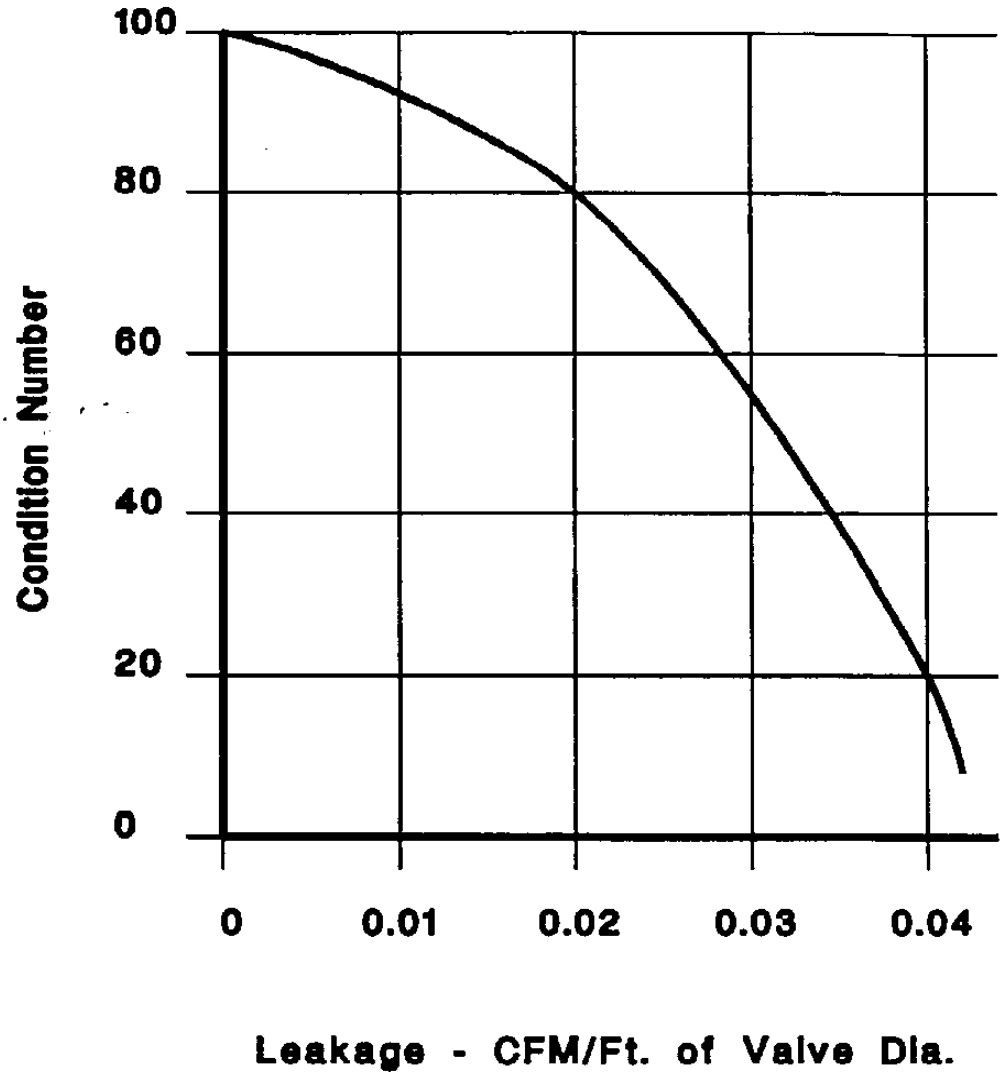
Filling Out Data-Evaluation Sheet

9-8. Enter the valve diameter in feet in box a. Fill in the measured water leakage in cubic feet per minute in box b. Calculate and record the ratio of leakage in cfm to valve diameter in feet in box c. Write down any information about the leak such as specific location, etc. in box d. Using the ratio of leakage to valve diameter from box c, go to Figure 9-1, and determine the valve seal leakage condition number. Place the valve seal leakage condition number in the lower right corner of the water seal leakage data evaluation sheet.

Frequency of Inspection

9-9. Water leakage past the valve seal should be evaluated once a year, or during overhauls. If leakage appears to be excessive, the frequency of inspection should be increased.

Figure 9-1


100
80
60
40
20
0
Condition Number
0
0.01
0.02
0.03
0.04
Leakage - CFM/Ft. of Valve Dia.

REMR Hydropower Condition
Indicator Program

Data Evaluation Sheet
Overall Valve Condition

Project: *Old Hydro Plant* Unit No. _____

Type of Turbine: *Spherical*

Prepared by: *I.N. Spector* Date: *7/3/90*

a.	Valve Diameter (In.) -	*168*
b.	Water Leakage (Cubic Feet / Minute) -	*0.35*
c.	Cubic Feet / Minute / Ft. Dia. (12 x b. /a.)	*0.025*
d.	Remarks:	

Water Seal Leakage Condition Index Rating (From Figure 9-1)	*70*

Oil Seal Leakage (Spherical Valve Only)

Introduction

9-10. This inspection is used to determine the condition of the valve based on external oil leakage (visible) and internal oil leakage (not visible). This is only for valves with seals actuated by hydraulic oil. A condition number is assigned based on the leakage quantity and the valve size.

Instructions for Inspection

9-11. The quantity of oil leakage will be determined by measuring oil loss at the reservoir. The oil level should be marked at the sight gauge (if available) and dated. The oil volume must be calculated from the change in oil level. Oil loss per month must then be calculated to determine a condition number from Figure 9-2. This method will determine the total (both internal and external) oil leakage for the hydraulic system.

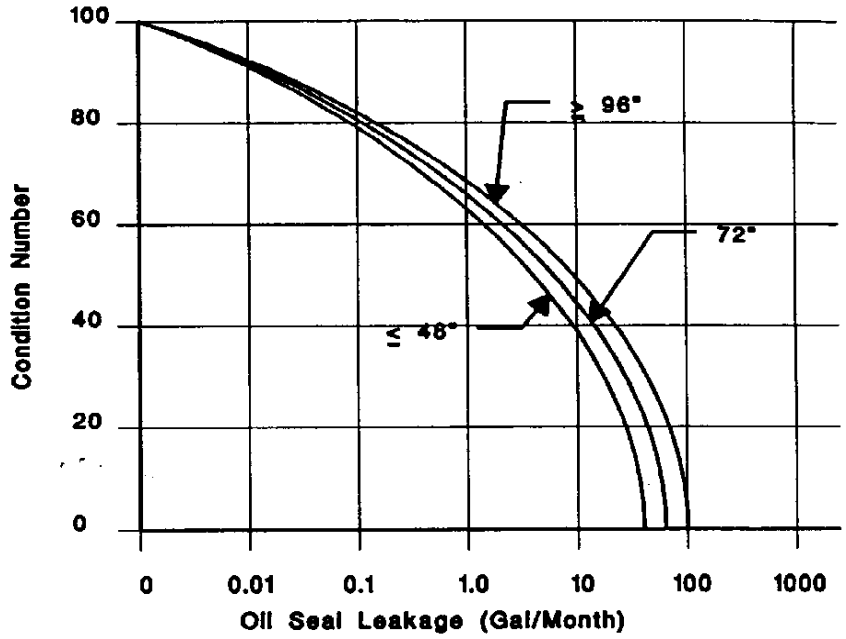
Filling Out Data-Evaluation Sheet

9-12. Enter the valve diameter in feet in box a. Fill in the measured oil leakage in gallons/month in box b. Write down any information about the leak such as specific location, etc. in box c. Obtain a condition number from Table 9-2. Place the valve seal oil leakage condition number in the lower right corner of the seal oil leakage data evaluation sheet.

Frequency of Inspection

9-13. Spherical valve oil leakage should be evaluated once a year, or during overhauls. If leakage appears to be excessive, the frequency of inspection should be increased.

Figure 9-2


100
80
60
40
20
0
Condition Number
≥ 96"
72"
≤ 48"
0
0.01
0.1
1.0
10
100
1000
Oil Seal Leakage (Gal/Month)

REMR Hydropower Condition
Indicator Program

Data Evaluation Sheet
Valve Condition - Oil Seal Leakage

Project: *Old Hydro Plant* Unit No. _____

Type of Turbine: *Spherical*

Prepared by: *I.N. Spector* Date: *7/3/90*

a.	Valve Diameter (In.) -	*168*
b.	Oil Leakage (Gallons / Month) -	*1*
c.	Remarks:	

Oil Seal Leakage Condition Index Rating (From Figure 9-2)	68

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Valve Condition

Project: _____Unit No._____

Type of Valve:_____

Prepared by:_____ Date: _____

Item	Date of inspection or test	Remarks	Condition No. 0-100
Water Seal Leakage			
Oil Seal Leakage			
		Overall Valve Condition Index Rating	

REMR Hydropower Condition
Indicator Program

Data Evaluation Sheet
Valve Condition - Water Seal Leakage

Project: _____Unit No._____

Type of Valve:_____

Prepared by:_____ Date: _____

a.	Valve Diameter (In.) -	
b.	Water Leakage (Cubic Feet / Minute) -	
c.	Cubic Feet / Minute / Ft. Dia. (12 x b. /a.)	
d.	Remarks:	

Water Seal Leakage Condition Index Rating (From Figure 9-1)	

REMR Hydropower Condition
Indicator Program

Data Evaluation Sheet
Valve Condition - Oil Seal Leakage

Project: _____Unit No. _____

Type of Valve: _____

Prepared by: _____ Date: _____

a.	Valve Diameter (In.) -	
b.	Oil Leakage (Gallons / Month) -	
c.	Remarks:	

Oil Seal Leakage Condition Index Rating (From Figure 9-2)	

PART X: GOVERNOR SYSTEM

Program, Format and Method

Explanation of Program

10-1. The overall governor system condition number is a number between 0 and 100 which will be used to define the present condition of the system. The number will be used in the REMR Condition Index Scale which is shown below.

The overall condition index is calculated from a series of tests and inspections, which are discussed later in this section. The criteria behind these tests and inspections are such that they may be performed during an annual maintenance period (generally 1-2 weeks).

Condition Index Scale

Value		Condition Description
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate
25-39	Poor	Serious deterioration in at least some portions of equipment. Function is still adequate.
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Specific test procedures and descriptions will not be covered in this Condition Indices Program. It is assumed that individuals performing the tests to determine a condition have performed these tests previously, and have had experience in the testing and inspection of hydroelectric generators and governors. Only experienced personnel should attempt to perform these tests.

Governors are complex mechanical or hybrid electro-mechanical control systems. A complete condition assessment requires a combination of performance tests as well as inspection and measurement of internal components. Disassembly is not practical for on-going routine condition assessment so we are limited to external inspections and performance tests. As was the

case for the automobile example discussed in the introduction of this report, these tests and inspections provide indirect but useful information about governor condition.

Since condition assessment under this program is so dependent on governor performance, it is important to separate performance deficiencies caused by governor condition from those caused by incorrect adjustments (dashpot, linkage or gain settings). In order to draw meaningful condition information from performance tests, the following must be assumed:

a. Accurate governor settings are available and installed in the governors. These would include, depending on governor type, permanent and temporary droop, and proportional, integral and derivative gain settings, (both on-line and off-line). Off-line and on-line step response curves produced by a correct computer model using these settings should be available to the test crew. The model and the settings should not be assumed to be correct until they have been verified by power system stability simulation. This is normally performed by the utility or power marketing administration which owns the transmission system to which our plant connects. Where governors control Kaplan turbines through 3-D cams, up-to-date tables for head wicket gate position-turbine blade position should be available.

b. Routine and breakdown maintenance is being performed. Before inspections and tests are performed for this condition assessment all reasonable adjustments and repairs will have been performed. These would include position and pressure switch adjustments, checks of shutdown sequences, circuit board or other component replacements as possible from spares supplies, oil pump repair or refurbishment and repair of piping oil leaks at accessible flanged, compression fitting or threaded joints. These would not include remachining of linkage pivot surfaces or any repair operation involving disassembly of pilot or distributing valves.

Stable governor operation is influenced by mechanical and water starting times which relate to generator and turbine design as well as the water passage. There are also varying demands placed on governors depending on-power system needs and plant control regime. For instance, will the generator be tripped off the power grid during a system breakup or will it supply a local load pending system reassembly - a more challenging task from a governing point of view? Will the unit be base loaded or will it be subjected to rapid load change? Will the unit be subjected to frequent load rejection and significant periods of off-line operation? Because of these varying conditions, a given level of governor performance as related to acceptance test criteria may quite satisfactory in one powerplant and wholly unacceptable in another. In recognition of this fact, tests in this section concentrate on directly observable or measurable performance as it relates to the performance expectations of the governed system at the particular powerplant.

Individual tests and inspections may not have the same importance or weight as other tests. The overall condition index value will be determined from the lowest individual condition number. If no previous test data is available, or the test shown is not done, then the condition for that individual test should be 100. The condition numbers match the text descriptions. The allowable range for the condition numbers follows in parentheses. Actual numbers will be based on the evaluator's judgement but will lie within the range indicated.

Explanation of Format

10-2. The formats used to address the various tests and inspections are similar. The first section is an introduction which describes the test or inspection. The second section gives instructions on how to perform the test or inspection. The third section explains how to perform the evaluation of the data and how to fill out the appropriate part of the Data Evaluation Sheet. The final section gives the recommended frequency of performance for the test or inspection.

Explanation of Method

10-3. A condition number between 0 and 100 is determined based on the results of tests and inspections. The overall condition index rating for the governor system is the lowest value of any of the condition numbers.

Overall Governor Condition

Introduction

10-4. The overall governor condition is calculated using the following condition indicators:

1. Off-line Performance
2. On-line Performance
3. Oil Pressure Leak-down Rate
4. Visual Inspection

Each indicator is assigned a condition number. The condition numbers are calculated based on the results of various tests and inspections which are discussed later.

Filling Out Data Evaluation Sheet

10-5. Column 1 lists the 4 condition indicators which are used for governor evaluation. Others may be added in the future. Fill in the date the test or inspection was made in column 2. Insert any notes or remarks about the condition number in column 3. For instance, if the condition number is low, put in the reason for it being low. Put the condition number for the particular condition indicator in column 4.

The overall governor condition index rating is the lowest of the individual condition indicator numbers. This rating is placed in the box in the lower right corner of the Overall Governor Condition Data Evaluation Sheet.

A sample of this form is shown on page D-98. Information to be completed by the field is shown in script text.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Governor System Condition

Project: Old Hydro Project Unit No. 1

Prepared by: I.N. Spector Date: 7/3/90

Item	Date of inspection or test	Remarks	Condition No. 0-100
Off-Line Performance	*7/3/90*	*Speed can't be consistently controlled by autosynchronizer-incomplete sequence. No oscillation or speed drift*	*40*
On-Line Performance	*7/3/90*	*Step response marginal*	*50*
Oil Leak Down Rate	*7/3/90*	*Leak down rate 30% higher than baseline*	*55*
Visual Inspection	*7/3/90*	*Heavily worn link hinge pins. No pressure tank relief device on pressure tank.*	*30*
		Overall Governor System Condition Index Rating	30

Off-Line Performance Evaluation

Introduction

10-6. This evaluation is used to determine the condition of the governor based upon off-line performance. Off-line operation of units is generally limited to that period after startup prior to synchronizing to the line and the period after main breaker trip prior to shutdown or resynchronization. Performance must be such that the generator can be synchronized to the line. Synchronizing may be done manually or by autosynchronizer.

Instructions for Evaluation

10-7. The condition number should be assigned based upon deterioration of governor condition as determined by off-line performance as follows:

Minor - The governor responds to speed adjust signals and holds speed without drift. Distributing valve spool oscillation is minimal and wicket gate position holds steady. Synchronization is accomplished in a timely way by manual synchronization or by properly adjusted autosynchronizer. In this case, the condition number is 85 (55-100).

Moderate - The governor responds to speed adjust changes but speed may drift slowly. Distributing valve spool oscillation may be significant and some wicket gate oscillation may be evident. Levels of movement are such they can be sustained for long periods (many hours) without causing equipment damage. Synchronization by a properly adjusted autosynchronizer is too slow or erratic to be usable or will not synchronize. Manual synchronization by the operator can be done consistently. The condition number is 30 (25-54).

Major - Governor response to speed adjust signals is erratic and speed drift is so significant that synchronization by an operator is slow and difficult. Use of autosynchronizer is out of the question. Distributing valve and gate movement may be substantial. The condition number is 20 (10-24).

Failed - Speed control is so unstable that synchronization is impossible under any circumstances. The condition number is 0.

If performance deterioration is such that settings must be readjusted at other than annual maintenance intervals, subtract 20 from the condition numbers for minor, moderate and major categories.

Filling Out Data Evaluation Sheet

10-8. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

10-9. Off-line performance evaluation should be performed at annual maintenance.

On-Line Performance Evaluation

Introduction

10-10. This evaluation is to determine the condition of the governor based on its ability to meet system stability and load change requirements. While speed control performance of the governor is readily observable off-line or even while supplying local load, most Corps units are connected to large systems which are essentially infinite buses. Determination of on-line governor performance as it relates to system stability must be by step response testing. Oscillograph results must be compared to the response for the optimized computer simulation. "Optimize" refers to the computer model, including gains, droop values and time constants, verified by power system computer simulation, which best meet system needs. Load change in response to control signals (megawatts per minute) can usually be checked using a stopwatch. Permanent droop (or speed regulation) should be verified to match panel meters.

Instructions for Evaluation

10-11. The condition number should be assigned based on degree of condition deterioration based on on-line operating characteristics as follows:

Minor - With proper settings installed in the governor, the step response curve matches that generated by the computer model. Load change response to control signals from plant control system meet all requirements for rate and repeatability. The condition number is 90 (85-100).

Moderate - The step response shows slightly greater overshoot, longer settling time or greater than expected steady state oscillation but net performance is well within system requirements as confirmed by transmission system engineers. Load change response meets control needs. The condition number is 60 (55-84).

- Step response shows considerably more overshoot, longer settling time and more steady state oscillation than the computer model. System engineers confirm that performance is marginally acceptable. Some distributing valve oscillation, which cannot be adjusted out, may be present. Load change response is acceptable. The condition number is 50 (40-54).

Major - Step response does not meet system criteria. Governor displays poor response to load change commands. Load may drift off setpoint. May be significant distributing valve oscillation and some wicket gate oscillation which cannot be tuned out. The condition number is 30 (25-39).

- Performance degraded to the point that system operators consider the governor to be a detriment to system stability. They may request the unit be operated 'last on, first off". The condition number is 15 (10-24).

Failed - Governor is not reliably operable. It may not be capable of safe gate operation, it may not hold load setpoint, or it may produce unacceptable gate oscillation. The condition number is 5 (0-9).

If performance deterioration is such that settings must be readjusted at other than annual maintenance intervals, subtract 20 from the condition numbers for minor, moderate and major categories.

Filling Out Data Evaluation Sheet

10-12. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

'Frequency of Inspection

10-13. On-line performance evaluation should be performed during annual maintenance.

Oil Leak-Down Rate

Introduction

10-14. This is an indirect indicator of valve seal condition within the governor. The oil leak down rate is the rate of pressure loss in pounds per minute due to internal leakage. This test is strictly comparative and should not be used without baseline data from the same governor when new it was new or from an identical new or rebuilt governor. The simplest form of this check is to measure rate of governor pressure loss with the unit under normal shutdown (gate on "squeeze"). This will include leakage past one set of sealing surfaces in the pilot and distributing valves, the pump check valve and the turbine gate servomotor piston rings. Shutting off the isolation valves to the turbine gate servos (after unwatering to tailwater) will reduce leakage contribution to governor components only. Further refinement of the test to measure leakage past alternate sealing surfaces with the governor operating in the "gate open" direction could be done but it is not expected to yield significant additional information.

Instructions for Evaluation

10-15. The combined leak-down (governor and turbine servos) rate is not of interest except if it keeps the governor from completing the required number of full servo strokes with the governor pumps off. The number of strokes may be found in the procurement specifications or in the governor O&M manual. Such limited operation affects operating safety and should be corrected before the unit is returned to service. If governor leakage is found to be the problem, the governor should be assigned a condition number of 10.

The leak-down rate for governor alone should be compared to baseline. The relationship between leak-down rate and condition number is as follows:

Leak-down Rate (x baseline)	Condition Number*
1 to 1.1	(85-100)
1.2 to 1.3	(55-84)
1.4 to 1.5	(40-54)
greater than 1.5	30**

* Use linear interpolation to find condition number.

** Only if pump starts and operating hours are causing overheating or excessive pump wear. Otherwise condition number cannot be lower than 40.

Filling Out Data Evaluation Sheet

10-16. Column 1 lists the test name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

10-17. The oil leak-down rate should be determined at each annual maintenance.

Visual Inspection

Introduction

10-18. This evaluation is used to determine the condition of the governor based upon visual inspection. The governor, including the pressure and sump tanks, piping and mechanical linkages should be thoroughly examined.

Instructions for Evaluation

10-19. This procedure involves the careful inspection of the governor. The following general information is provided for the visual inspection:

- Pressure vessel inspection should be provided per EM 385-1-1 Safety and Health Requirements Manual. This involves examination of welds, extent of corrosion and condition of pressure relief devices.

- Oil leaks should be noted. Of particular interest are leaks from casting porosities or cracks and leaks from gasketed joints of large assemblies such as the distributing valve.

- Inspect for linkage wear at hinged or sliding joints. Look at gate and blade position feedback cables and sheaves.

- Look for cracked pipe or structural welds. When the opportunity arises to drain the sump tank, inspect any piping inside the tank. Also inspect the tank itself for cracked welds and corrosion.

Condition numbers for extent of condition deterioration based on visual inspection fall into the following three categories:

Minor - No cracks in distributing valve assembly or other major governor components. Leaks at gasketed joints, if any, are not more than seeps. Wear at linkage pins and sliding surfaces is minimal. Feedback cables have no kinks, flat spots or broken strands and sheaves rotate freely. No cracks in pipe or structural welds noted. Only minor surface corrosion noted in sump tank. The pressure tank passes inspection in all areas. The condition number is 80 (70-100).

Moderate - The occasional surface crack may be noted in distributing valve or other assemblies. Minor leaks at gasketed joints. Some play at pivots; visible wear on pivot pins and scoring on sliding surfaces. Flat spots in feedback cables and wobbling or binding in cable sheaves may be seen. A few minor weld cracks may be observed in pipe or structural welds. Significant surface rust may be present in the sump tank. Signs of paint failure and resultant rust may be found in the pressure tank. The condition number is 50 (40-69).

Major - Full depth cracks as evidenced by oil seepage found in distributing valve casting or welded pressure pipe joints. Significant leakage at gasketed joints and valve spool packing. Obvious play at linkage pivots and signs of sticking or chattering at sliding surfaces. Feedback cable kinks, partial wear-throughs and broken strands may be observed; some sheaves may be broken or locked up. May be full depth structural cracks present. Signs of deep pitting corrosion in sump tank with potential for perforation of tank wall. Significant corrosion noted in pressure tank. Pressure relief device may be inadequate in capacity or operation. The condition number is 30 (10-39).

Failed - Indications of potential catastrophic failure of any component in the high pressure oil system. The condition number is 9.

Filling Out Data Evaluation Sheet

10-20. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

10-21. Visual inspection of governor components should be performed during annual maintenance. Inspection of pressure and sump tanks should be done annually or at intervals customary for the plant, not to exceed 5 years.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Governor System Condition

Project: _____ Unit No. _____

Prepared by: _____ Date: _____

Manufacturer: _____

Item	Date of inspection or test	Remarks	Condition No. 0-100
Off-Line Performance			
On-Line Performance			
Oil Leak Down Rate			
Visual Inspection			
		Overall Governor System Condition Index Rating	

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Governor Off-Line Performance

Project: _____ Unit No. _____

Prepared by: _____ Date: _____

Manufacturer: _____

Equipment Used:

Performance Description:

1. Response to speed adjust

   Manual -

   Autosynchronizer -

2. Distributing valves/wicket gate oscillation -

3. Speed drift -

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Governor On-Line Performance

Project: _____ Unit No. _____

Prepared by: _____ Date: _____

Manufacturer: _____

Step response test procedure attached

Step response oscillograph attach

Equipment Used:

Performance Description:

1. Step response

2. Load charge response

   Manual control from generator control board -

   Automatic load control by plant control system -

3. Distributing valve/gate oscillation -

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Governor Oil Leak - Down Rate Test

Project: _____ Unit No. _____

Prepared by: _____ Date: _____

Manufacturer: _____

Test Procedure -

Leak Down Rate - Combined governed turbine servomotors

Leak Down Rate - Governor only

Pump Cycle frequency

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Governor Visual Inspection

Project: _____ Unit No. _____

Prepared by: _____ Date: _____

Manufacturer: _____

Point of Reference	Description of Problems Noticed
Pressure Tank	
Sump Tank	
Cables and Linkage	
Oil Leaks	
Pipe & Valve Assembly Cracks	
Structural Cracks	

E
GLOSSARY OF TERMS

E.1 Introduction

This appendix contains a compilation of the hydraulic turbine and pump/turbine terminology used in this Volume. Synonyms for the terms used in this Volume are also provided. Diagrams of the various turbine and pump/turbine types are included to facilitate the identification of components.

All information in this section is taken from the Allis Chalmers Publication 54X10084-01 - *Standard Definitions and Nomenclature*.[1] The information is reproduced with the kind permission of Voith Hydro.

IEC Publication, Code No. 61346 - *Nomenclature for Hydroelectric Powerplant Machinery*[2] was published in July 1999 and is another source of standardized terminology.

E.2 Nomenclature and Definitions

1.0 GLOSSARY

1.1 Scope

[1] Allis-Chalmers Corporation, *Standard Definitions and Nomenclature*, Publication No. 54X10084-01, Allis Chalmers Corporation

[2] IEC/TR 61364 (1999-07) *Nomenclature for hydroelectric powerplant machinery*

This is a compilation of the terminology with descriptions for the principle components of hydraulic turbines and pump/turbines. Also included to facilitate identification and description of the components are drawings representative of various types and configurations of hydraulic turbines as well as certain components. The drawings are listed below and appear at the end of the Glossary.

Figure E-1	Vertical Fixed Blade Propeller Turbine
Figure E-2	Vertical Kaplan Turbine
Figure E-3	Vertical Francis Turbine
Figure E-4	Vertical Reversible Francis Pump/Turbine
Figure E-5	Vertical Impulse Turbine
Figure E-6	Vertical Impulse Turbine
Figure E-7	Wicket Gate Linkage
Figure E-8	Wicket Gate Mechanism
Figure E-9	Kaplan Runner Hub Assembly
Figure E-10	Kaplan Blade Tilt and Blade Angle

1.2 Component Nomenclature and Definitions

The terminology and descriptions that are presented below are preceded by an identification number. Each identification number also appears on one or more of the accompanying drawings to assist in identifying the component.

* Indicates that the particular identification number does not appear on any of the accompanying drawings.

1 Runner - the rotating element of the turbine which converts hydraulic energy into mechanical energy. For reversible pump/turbines, the element is called an impeller and converts mechanical energy into hydraulic energy for the pump mode.

1A & 1B Runner Blades/Buckets (or impeller vanes) - the contoured components of propeller, Kaplan, Francis and impulse runners that deflect the flowing water and transfer the energy to the runner crown hub or disc when operating as a turbine; or that transfers energy to the water when the impeller is operating as a pump.

1C Runner Crown - the upper axisymmetric portion of the runner which provides a mechanical attachment to the main shaft and to which the top of the runner blades (or impeller vanes), attach.

1D Runner Band - the lower axisymmetric portion of the runner to which the lower or outer ends of the runner blades (or impeller vanes), attach.

1E Runner Hub - the axisymmetric portion of a propeller and Kaplan runner which provides the attachment to the main shaft and to which the inner ends of the runner blades attach.

1F Runner Cone - the extension of the runner crown, or runner hub, that guides the water as it leaves the runner.

1G Runner Crown Seal - the close running clearance between the rotating runner crown and the stationary head cover. The close clearance restricts the flow of water into the chamber between the top of the runner and the bottom of the head cover.

1H Runner Band Seal - the close running clearance between the rotating runner band and the stationery bottom or discharge ring. The close clearance restricts the flow of

water between the high pressure zone and the low pressure zone of the runner/impeller.

2 Wearing Rings - replaceable rotating rings fastened to the runner or adjacent stationery rings fastened to the head cover and the bottom ring (or discharge ring), thus forming removable seals with small clearances.

3 Spiral Case - the spiral shaped water passage which completely surrounds the turbine providing a uniform distribution of water flow to the turbine. The upstream end of the spiral case connects to the pressure conduit or penstock.

4 Semi-Spiral Case - a concrete intake having direct flow to the upstream portion of the turbine and a spiral case surrounding the downstream portion of the turbine to provide uniform water distribution.

5 Vaned Intake Ring - the structural member in a tubular unit consisting of the outer conical ring, guide vanes and inner ring which supports the main guide bearing.

5A Guide Vanes - the streamlined stationary components in a tubular unit that span the waterway to provide support for the guide bearing and to provide direction to the water flowing to the runner.

6 Stay Ring - the structural member surrounding the wicket gates having two annular rings connected by a number of fixed stay vanes in the water passages. Its function is to provide support and structural continuity between the upper and lower portions of the turbine distributor, while guiding the water as it enters or leaves the spiral case (pump or turbine).

7 Stay Vanes - the streamlined stationary members which connect the upper and lower annular rings of the stay ring, and provide a rigid connection for the top and bottom turbine structures.

8 Nose (Baffle) Vane - a stay vane located at the junction of the small and large end of the spiral or semi-spiral case.

9 Bottom Ring - the stationary ring which contains the lower wicket gate bushings, and provides the water surfaces leading to or from the runner band or discharge ring and is bolted to the stay ring. It may be integral or separate from the discharge ring.

10 Discharge Ring - the structural member of a Francis turbine that surrounds the runner band. On a propeller and Kaplan turbine it surrounds the blades and forms a guide for the water. It may be integral with the bottom ring. The draft tube liner is attached to the down stream end of the discharge ring.

11 Draft Tube - the diffuser which regains the residual velocity energy of the water leaving the turbine runner or accelerates the flow as it approaches the pump impeller.

12 Elbow Draft tube - a diffuser in the form of an elbow.

***13 Inlet Valve** - the valve or gate that controls the water flow to the turbine.

14 Draft Tube Liner - the steel lining used in the draft tube to protect the concrete from the high velocity of the water.

15 Pier - the structural member used to support the upper surface of the horizontal portions of water passages such as the draft tube and the spiral case inlet.

16 Pier Nose - the steel lining used at the upstream ends of a pier.

17 Main Shaft - the rotating element that transmits torque developed by the turbine runner to the generator rotor or transmits torque developed by the motor the pump impeller.

17A Coupling Bolts - the fasteners that attach the main shaft to the runner (impeller) and to the generator (motor) or intermediate shaft.

17B Nut Guard - the protective cover over the coupling bolts and nuts.

18 Head Cover - the axisymmetric structural member in vertical machines that spans the top of the distributor, provides the separation between the watered runner chamber and the dry turbine pit and supports the main shaft packing box and the main bearing. In propeller, Kaplan and Francis machines the head cover also supports the upper wicket gate stems and is bolted to the stay ring.

18A Outer Head Cover - the outer section of a circumferentially split propeller or Kaplan head cover that supports the upper wicket gate stems and is bolted to the stay ring.

***18B Inner Head Cover -** the inner section of a circumferentially split propeller or Kaplan head cover. It is bolted to the outer or intermediate head cover and supports the main bearing and main shaft seal.

18C Intermediate Head Cover - the middle section of a circumferentially split propeller or Kaplan head cover that is bolted to the outer and inner head cover section.

18D - Not used.

18E Equalizer Line (Thrust Relief Line) - the pipe connecting the chamber between the top of the runner crown and head cover inboard of the runner crown seal to the draft tube.

19 Main Guide Bearing - the bearing located nearest the runner. On vertical machines it is typically a journal bearing. On the standard TUBE turbines it is a spherical roller bearing.

19A Bearing Shell - the removable element containing the material that forms the bearing surface.

19B Bearing Shoes - the individually adjustable elements of a segmented type journal bearing.

19C Bearing Housing - the outer casing of the main guide bearing that supports the shell or shoes and usually mounts on the head cover.

19D Oil Basin (Sump) - the collection reservoir for the main guide bearing oil. It is normally located just below the guide bearing.

19E Bearing Cover - the radially split cover which closes the oil reservoir and prevents contamination of the bearing oil system.

20 Wicket Gates - the angularly adjustable streamlined elements which control the flow of water to the turbine or discharge from the pump.

21 Gate Operating Ring - the ring rotated by the servomotors which distributes the force from the servomotors to the individual wicket gate linkages to provide simultaneous movement of all wicket gates.

22 Gate Servomotors - the hydraulic cylinders actuated by oil pressure which

supply the force necessary to operate the wicket gates through the gate operating ring.

22A Gate Lock - the device used to prevent actuation of the wicket gates by the servomotors.

23 Connecting Rods - the element connecting the servomotor piston rod to the gate operating ring.

24 Gate Mechanism - the components used to actuate the wicket gates consisting of the gate servomotors, the gate operating ring and the gate linkage.

25 Gate Linkage - all connecting linkage between the gate operating ring and the wicket gates.

25A Gate Lever - the arm which is attached to the wicket gate stem to transmit the actuating force from the gate mechanism to the wicket gate.

25B to 25E - Not used.

25F Shear Lever - the lever attached to the gate lever with the shear pin and connected to the gate operating ring through the gate link.

25G Gate Links - the connecting links between the shear lever and the gate operating ring.

25H Shear Pin - the replaceable protective device which is designed to fail by shearing when an obstruction prevents the wicket gate from moving.

25I Gate Link Pin - the pin connecting the shear lever and the gate link.

25J Eccentric Pin - the eccentric type link pin connecting the gate link and gate operating ring. The eccentric construction permits adjustments in the gate linkage to equalize gate closure.

26 Main Shaft Seal - a seal used to minimize leakage at the main shaft.

27 Packing Box (part of the main shaft seal) - an annular chamber surrounding the main shaft; containing pliable sealing material and having a movable gland permitting adjustment or replacement of the sealing material.

27A H-Ring - the spacer ring inserted between rings of pliable packing which permits a circumferential path for distributing lubricants.

27B Shaft Sleeve - the polished stainless steel (or bronze) ring fastened to the shaft to provide a mating surface for the packing.

28 Check Valve - an air vent that opens on increasing differential pressure between a negative pressure zone in the water passages and outside atmosphere.

29 Wicket Gate End Seals - the metallic or elastomeric strips that are retained in annular grooves in the head cover and the bottom ring to provided sealing contact with the ends of the wicket gates.

30 Flexible Coupling - the shaft connection in a tubular unit between the speed increaser and the generator which can accommodate minor misalignment.

31 Turbine Pit - the open space on a vertical unit between the head cover and the generator. It provides access to the gate mechanism, the main guide bearing, and the main shaft seal.

32 Pit Liner - the plate steel lining in the turbine pit. It serves as an internal form and as a protective liner for the surrounding concrete.

33 Turbine Walkway - the platform in the turbine pit which facilitates inspection and servicing of the gate mechanism, the main guide bearing and the main shaft seal.

34 Air Valve - the adjustable vent for admitting air to a waterway zone near the runner.

35 Water Deflector - the ring attached to the main shaft which slings leakage water outwards to the head cover drainage system.

35A Oil Deflector - the ring attached to the main shaft below the bearing which deflects oil into the oil basin.

36 Main Shaft Position Indicator - the pointer mounted on the bearing cover and aligned with a scribed line on the main shaft. Its purpose is to provide a visual indication of the vertical position of the shaft.

37 Man Door - a door installed to permit access for inspection and maintenance.

38 Turbine Piping - a general term to cover the air, oil, water supply and drainage piping within the turbine pit.

39 Distributor - the assembly which includes the stay ring, wicket gates, head cover and bottom ring. Its "centreline", in a vertical machine, is a horizontal plane equidistant from the top and bottom of the wicket gates.

40 Runner Hub Assembly - the assembly consisting of the runner hub, blades, cone, and including all of the runner blade operating mechanism that is used to adjust the pitch or angle of the runner blades.

40A Runner Blade Trunnion - the shaft segment integral with or bolted to the runner blade. It transfers the rotating action of the operating mechanism to the runner blades and supports the blade in the hub bearings.

40B Rocker Arm - the lever that attaches to the runner blade trunnion and connects to the blade link.

40C Blade Link - the element that connects the rocker arm to the crosshead through the link bolt.

40D Blade Link Bolt - the element that attaches the link to the crosshead and the rock arm.

40E Crosshead - the member that is integral with the blade servomotor and through links and rocker arms transmits the operating force to all blades simultaneously.

40F Drain Valve - the manually operated valve that is used to drain the oil from the hub.

41 Blade Servomotor - the hydraulic cylinder actuated by governor oil pressure which supplies the force necessary to adjust the runner blades. For the design shown, the piston is stationary and the cylinder barrel (with integral crosshead) moves axially on suitable supports.

42 Blade Tilt - on Kaplan runner blades the sine of the blade tilt angle is defined as the axial distance between two points on the periphery of the blade (one at the entrance edge and one at the discharge edge) divided by the chord between these two points.

42A Blade Angle - on Kaplan runner blades the sine of the blade angle is defined as the axial distance between two points on the periphery of the blade (one at the entrance edge and one at the discharge edge) divided by the arc length along the blade periphery between these two points.

43 Blade Servomotor Piston - For the design shown the stationary element that provides attachment for the oil pipes and separates the high pressure and return chambers within the servomotor.

44 Blade Cylinder Cap - the end cover for the servomotor cylinder that includes an extension to mate with the servomotor support bushing.

45 Speed Increaser - the geared drive unit which increases turbine shaft speed to drive the generator at an optimum speed for power generation. The speed increaser contains bearings that provides the necessary shaft support and thrust capacity.

46 Stay Column Assembly - the structural component which consists of the inner and outer stay cones connected by stay columns and/or stay vanes across the water passage; and which transmits the loads from the bulb unit to the powerhouse structure.

46A Stay Column, Upper/Lower - the structural components that span the waterway to provide support to the turbine and to the generator in a bulb unit, transmitting the forces to the powerhouse structure. Both upper and lower stay columns can contain access tubes to the turbine compartment.

47 Stay Cone, Inner/Outer - the plate steel components that line the inner and outer surfaces of the water passage and function with the stay columns and/or the stay vanes to transmit bulb loads to the powerhouse structure.

48 Outer Gate Barrel - the conical section of the outer wall of the water passage which provides the outer support for the wicket gate stem bushings and, in most cases, for the gate operating ring.

49 Access Tube - the watertight passage providing access between the generator compartment and the powerhouse, and between the turbine compartment and the powerhouse. Frequently, access turbines to the turbine compartment are provided in both the upper and lower stay columns.

50 Bulb - the streamlined watertight housing for the generator.

50A Inner Gate - the conical section of the bulb that provides support for the inner wicket gate stem bushings.

50B Bulb Nose - the spherical upstream section of the bulb.

51 Oil Pipes - the concentric pipes in the shaft that conduct the soil supplied by the governor for the actuation of the blade servormotor and for pressurizing the runner hub.

52 Housing - the enclosure, surrounding an impulse runner, which forms the aerated chamber in which the runner operates.

53 Brake Jet - the water jet tat provides the counter-rotational force used to decelerate the runner.

54 Needle - a moving element which is actuated by the governor, the servomotor or by hand mechanism to control the size of the jet impinging on the bucket

55 Nozzle - the shaped water passage which, with the needle, produces the jet and controls the rate of water flow.

56 Intake Pipe - the connecting water passage from the spiral case to the nozzle assembly.

57 Deflector - the device within the housing that is actuated by the governor for deflection of all or part of the jet away from the buckets, and therefore regulating the power output with a minimum effect on flow.

58 Instrumentation - the devices that sense temperature, flow, pressure, liquid level or RPM, and provides visual indication and/or electrical signals so that control functions can be energized manually or automatically.

59 Vent - the piping that provides atmospheric air to internal chambers for ventilation and pressure equalization.

60 Erection Joint - a slip joint that permits relative movement between adjoining parts. Leakage is controlled by a suitable seal arrangement.

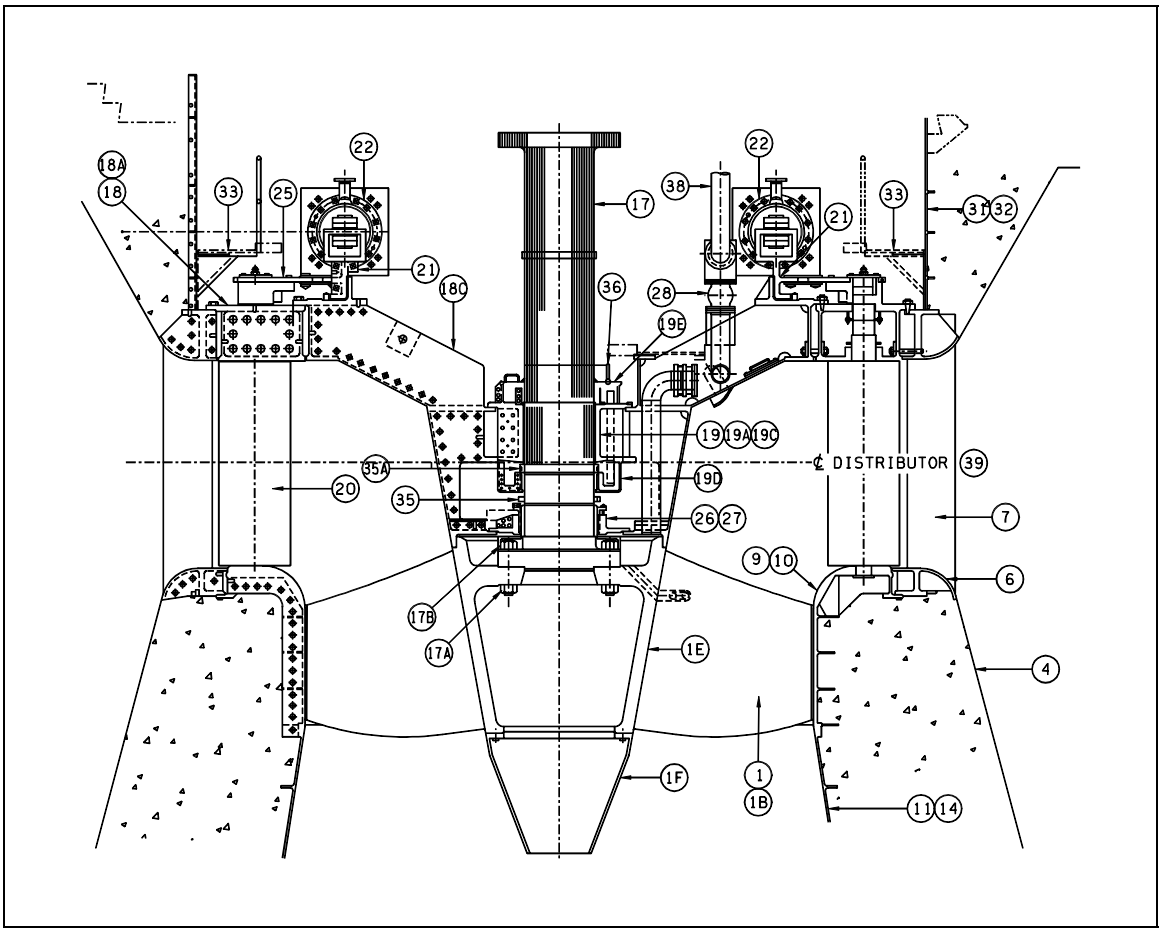


Figure E-1
Vertical Fixed Blade Propeller Turbine

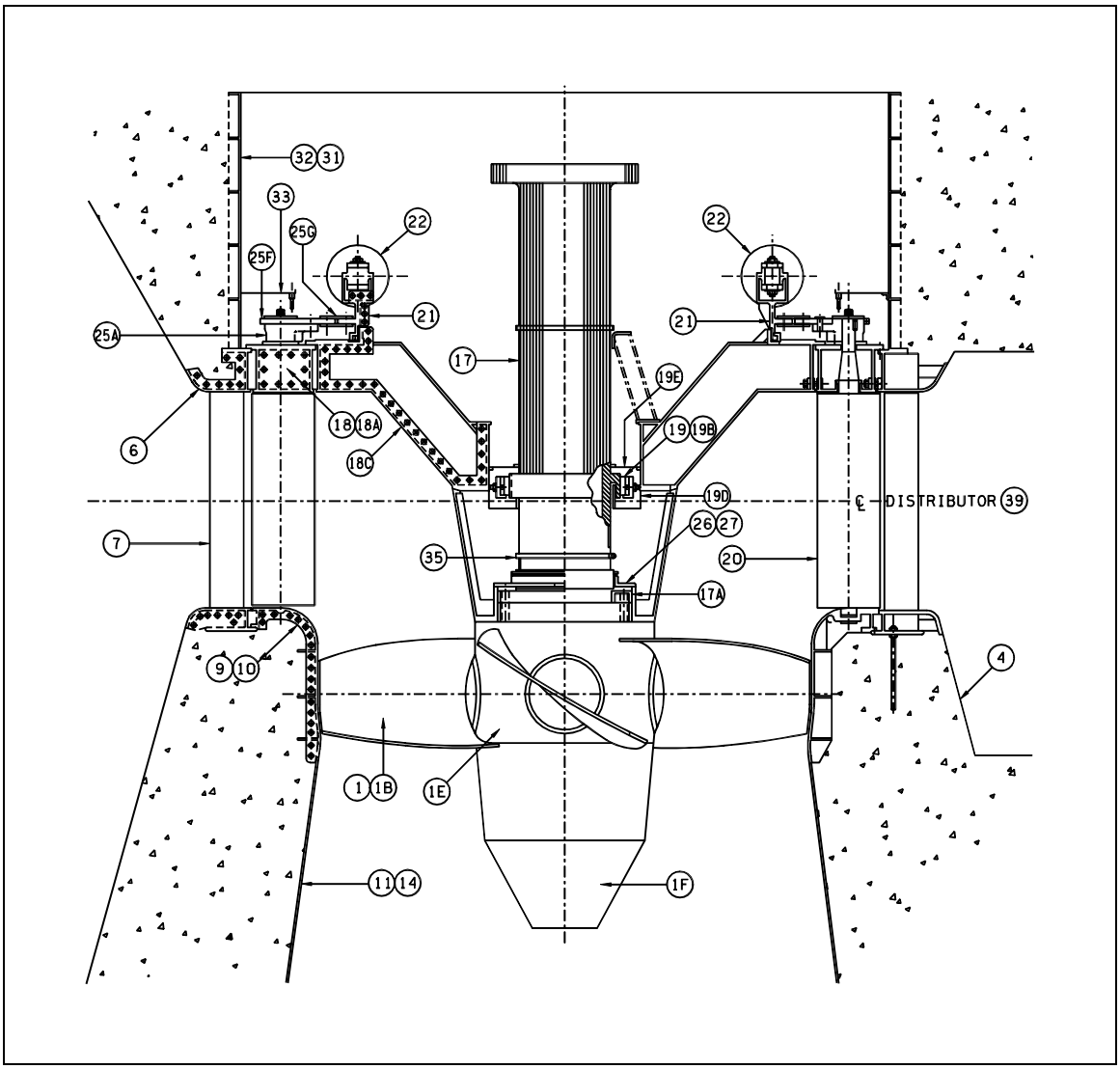


Figure E-2
Vertical Kaplan Turbine

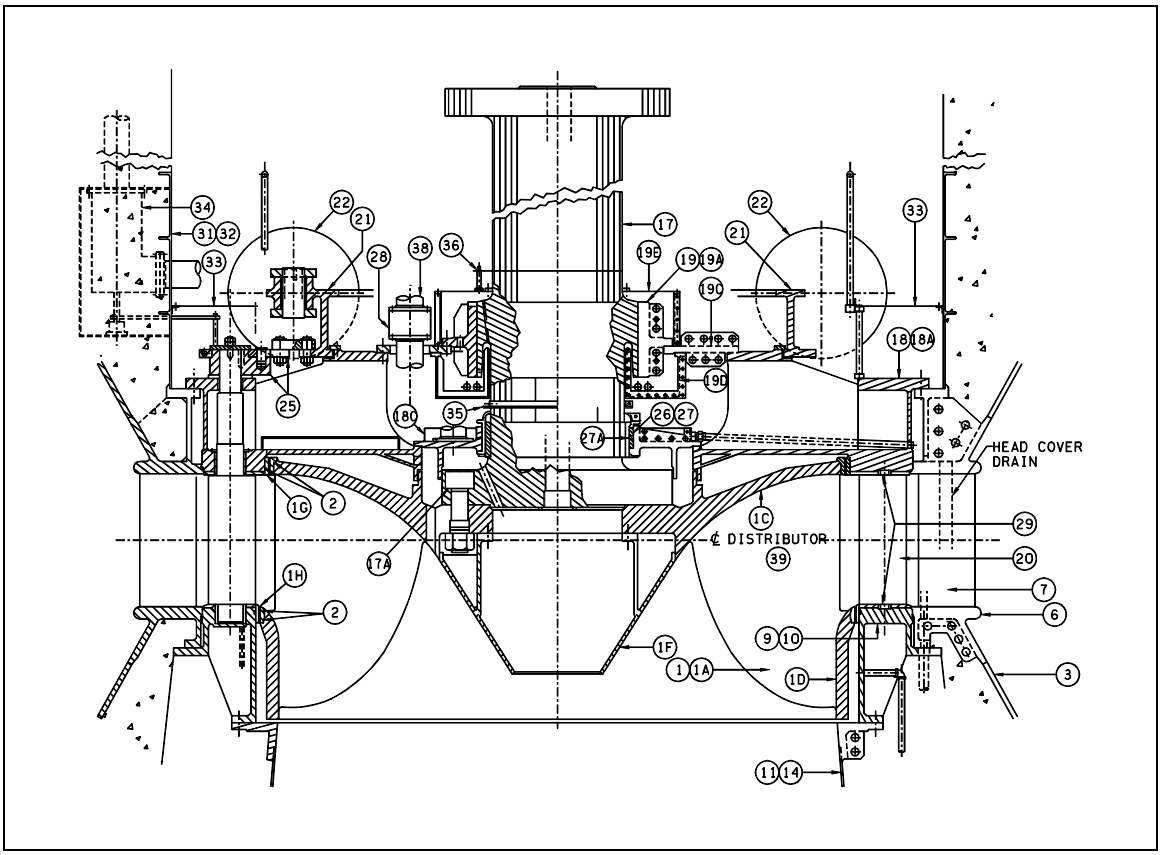


Figure E-3
Vertical Francis Turbine

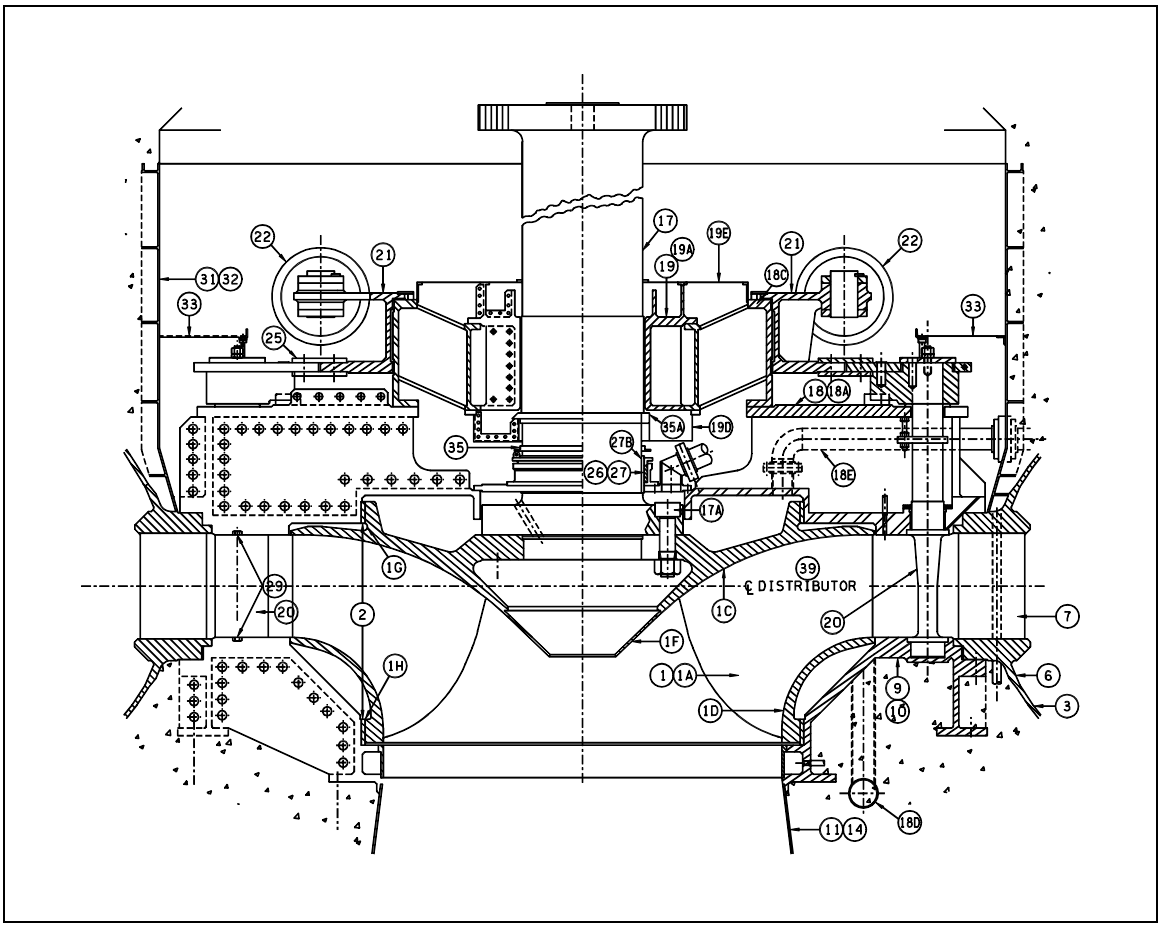


Figure E-4
Vertical Reversible Francis Pump/Turbine

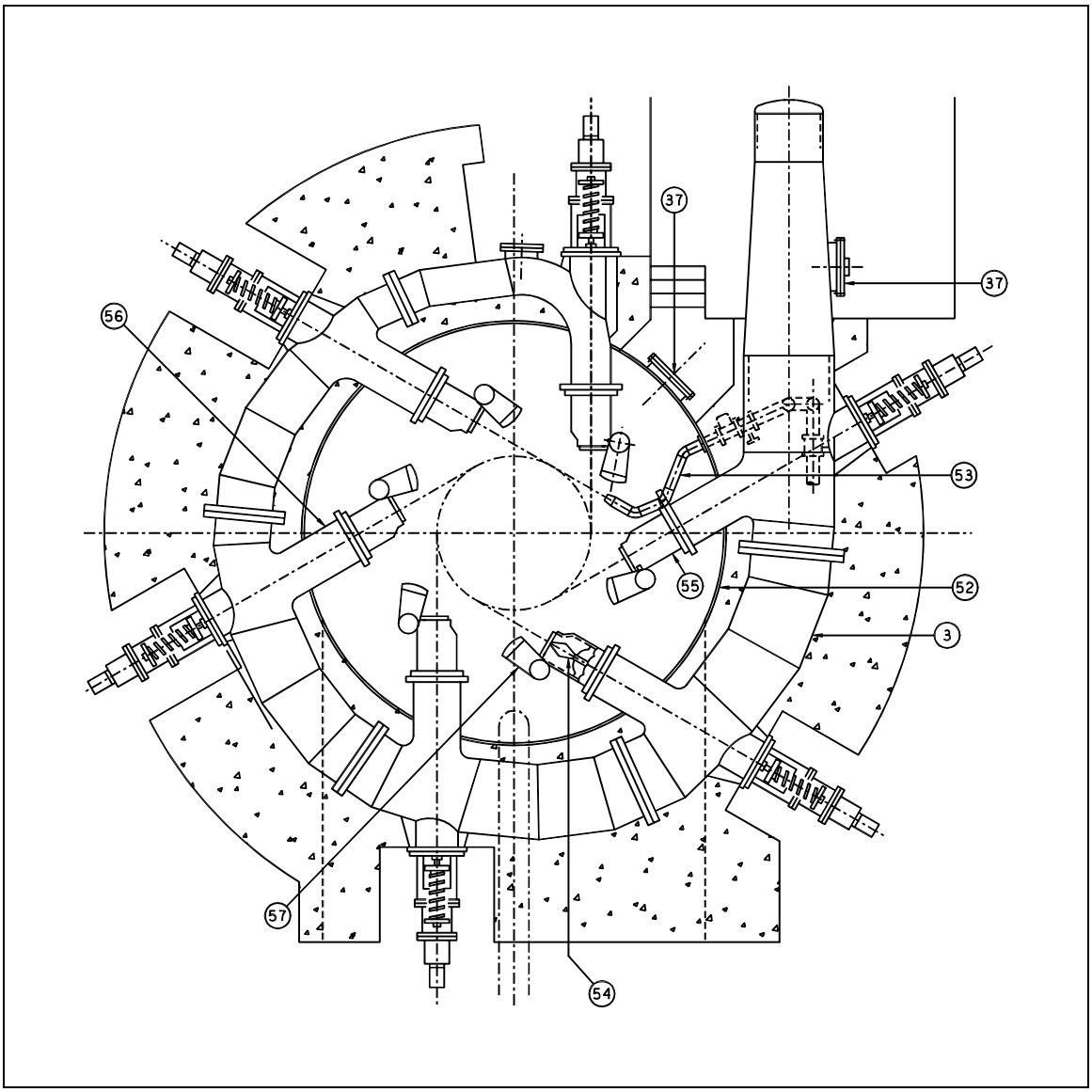


Figure E-5
Vertical Impulse Turbine

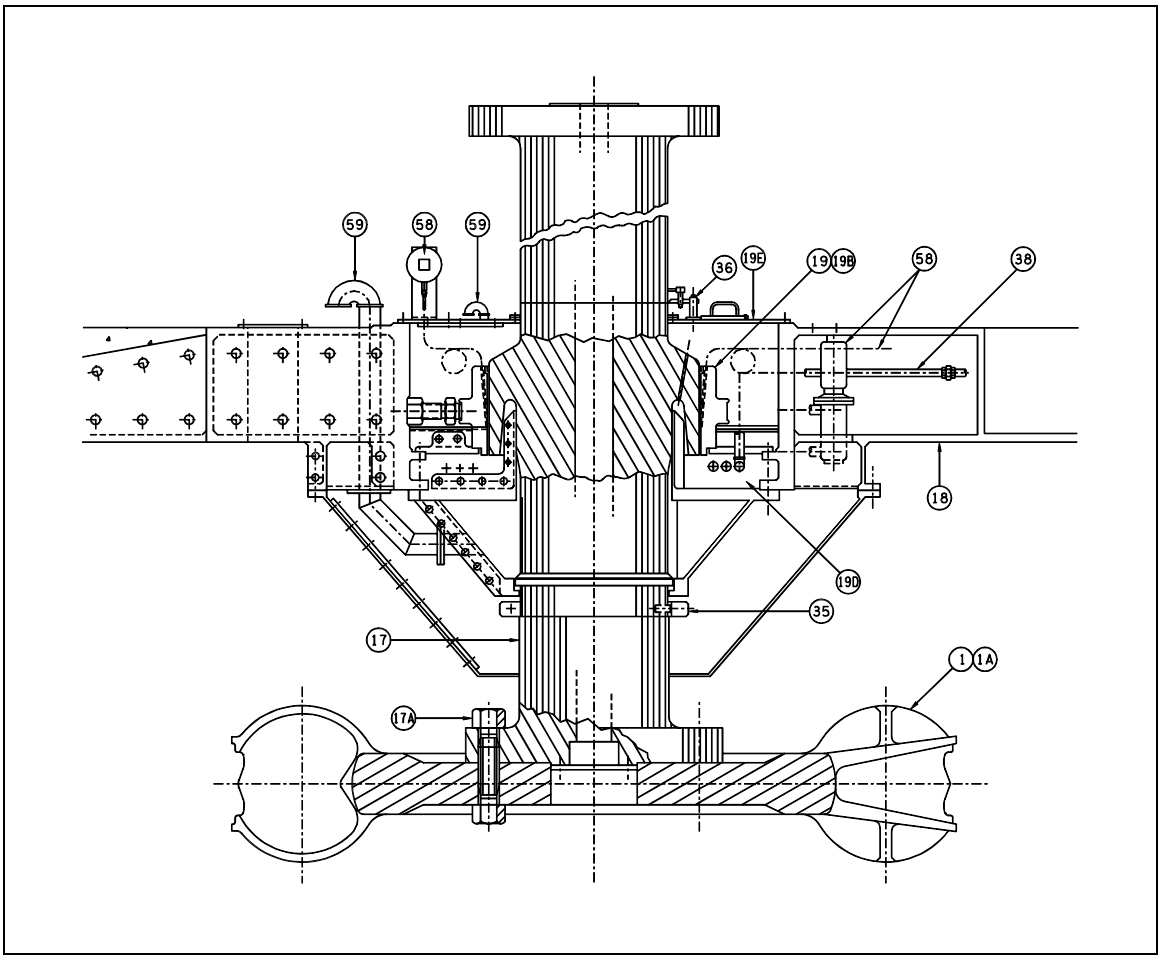


Figure E-6
Vertical Impulse Turbine

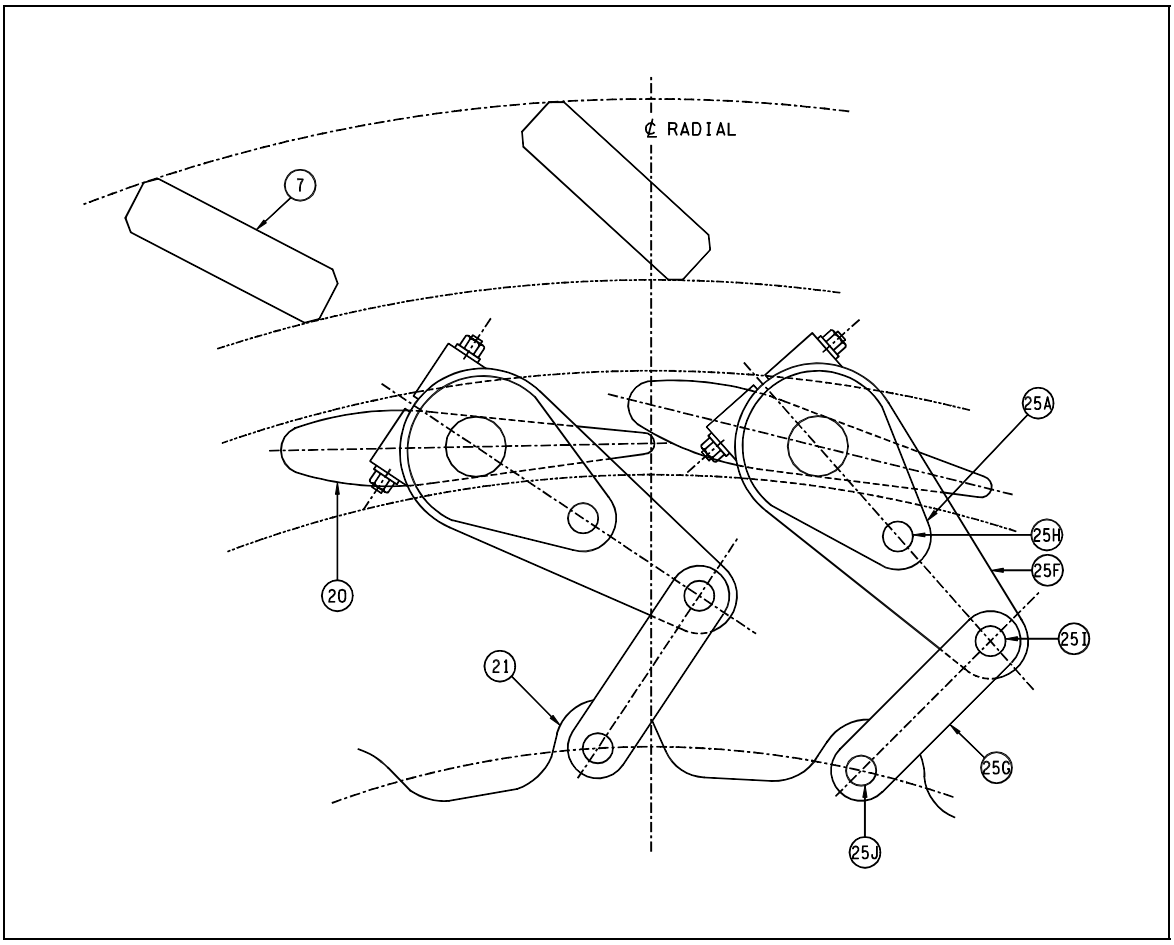


Figure E-7
Wicket Gate Linkage

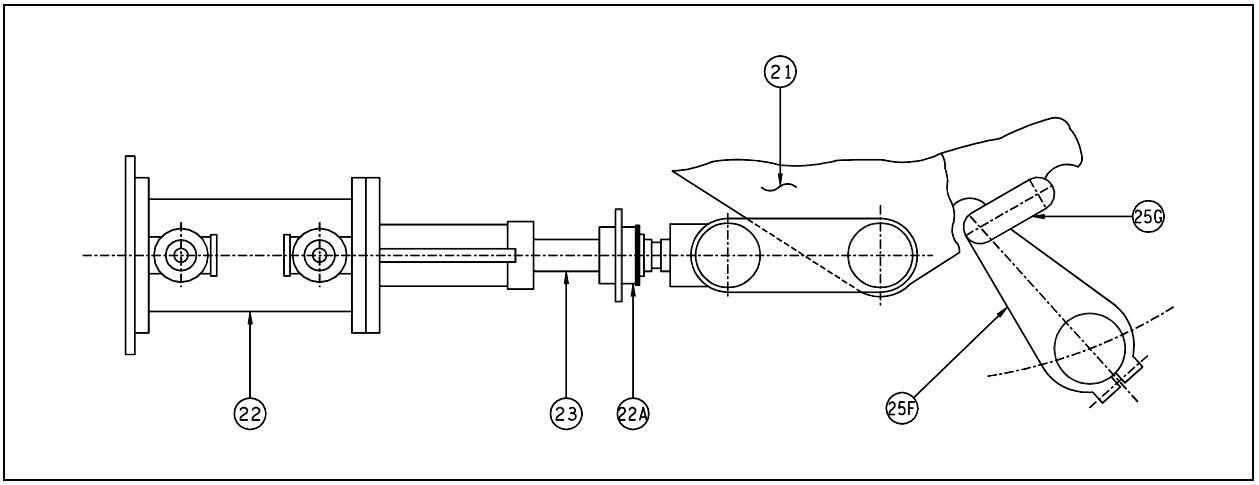


Figure E-8
Wicket Gate Mechanism

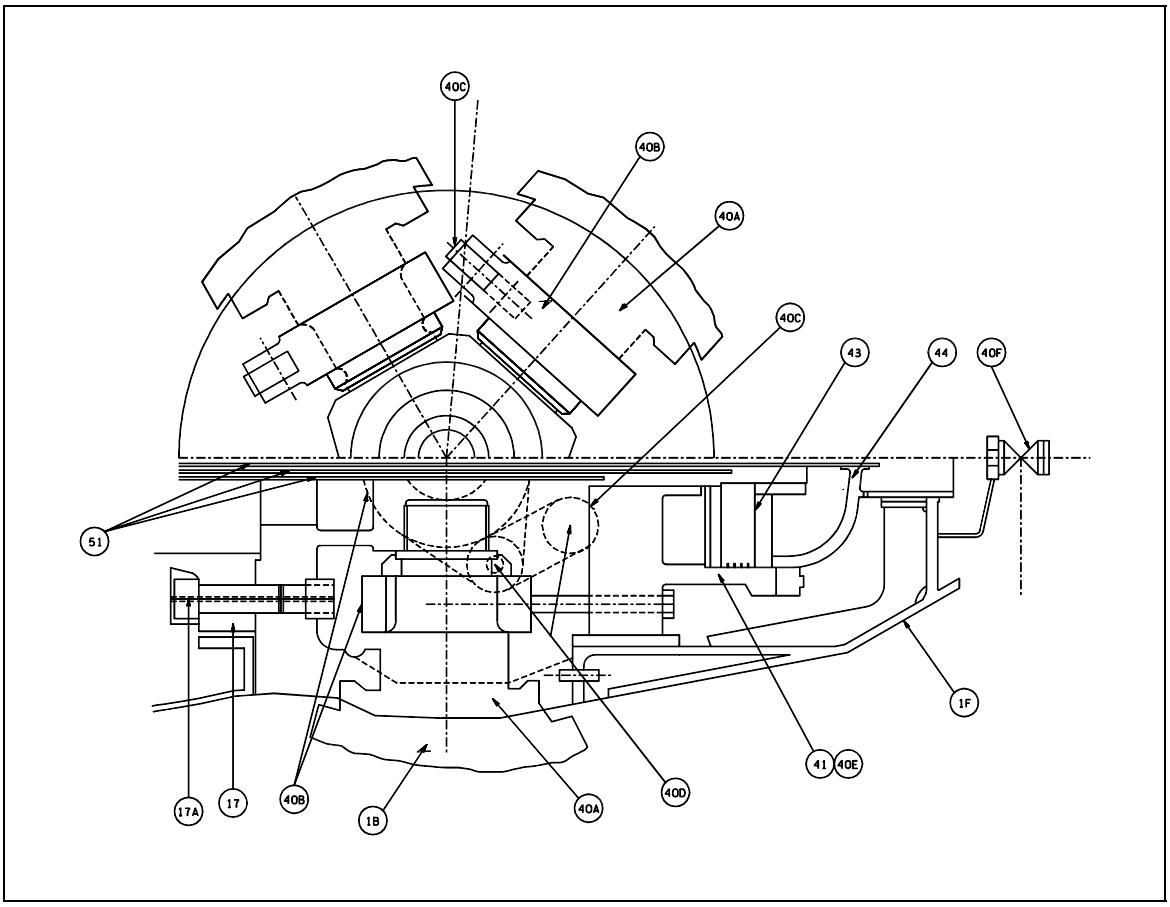


Figure E-9
Kaplan Runner Hub Assembly

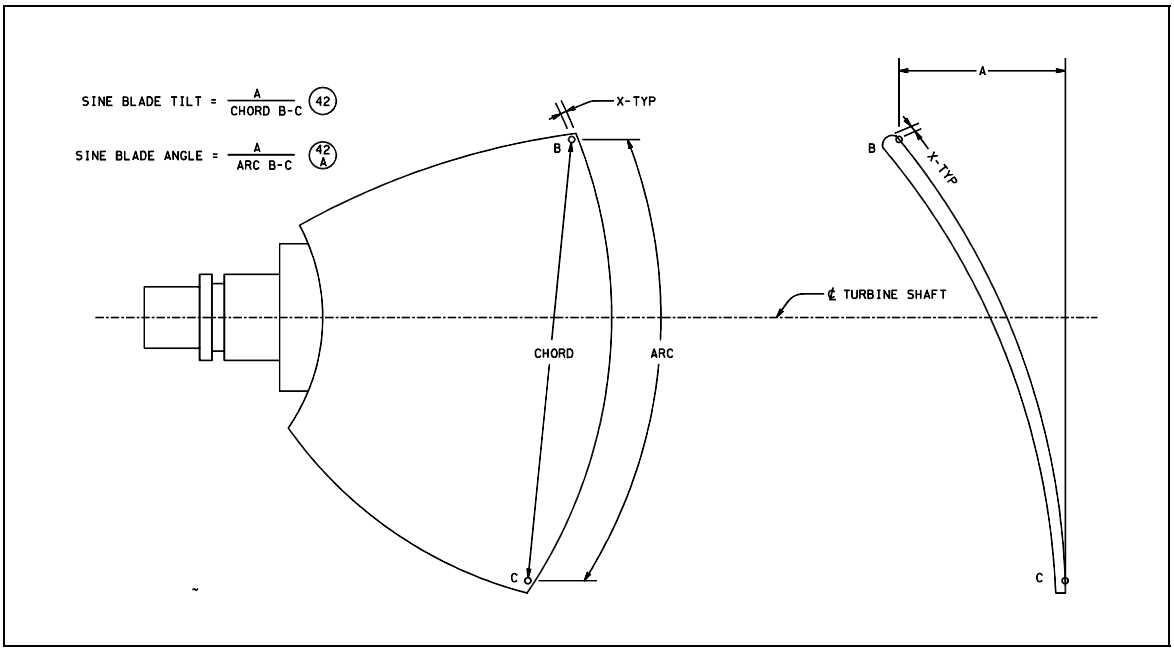


Figure E-10
Kaplan Blade Tilt and Blade Angle

Targets:

Hydropower Operations and Asset Management

Relicensing Forum

Plant Maintenance and Life Management

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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Printed on recycled paper in the United States of America

TR-112350-V2

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